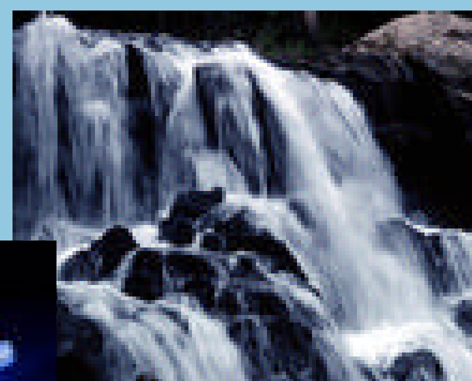
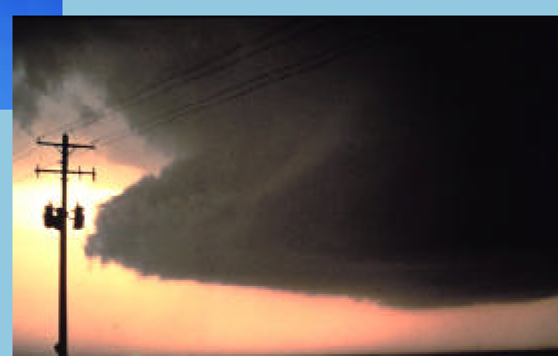
Vermont

ELECTRIC PLAN 2005

January 19, 2005





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Vermont Department of Public Service
2005 VERMONT ELECTRIC PLAN

January 19, 2005

Pursuant to 30 V.S.A. § 202(b) and § 202b(a)

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EXECUTIVE SUMMARY
Vermont Twenty Year Electric Plan 2005

This is Vermont's *Twenty Year Electric Plan 2005*. This document replaces the previous Plan adopted in December 1994.

This Plan serves to help guide utilities in their own planning activities by establishing a standard of planning and analysis for utilities. The Plan supports and guides Department actions in public advocacy before the State and federal regulators. Similar to prior plans prepared by the Department, this Plan is not a prescriptive resource plan. Several resource portfolios are, however, presented in the document for reference and discussion. The Electric Plan is designed to help guide utilities and the state to operate in a coordinated manner consistent with legislated goals and a supportive regulatory and policy environment. As with prior electric plans, this Plan provides broad guidance to utilities, regulators and policy makers to move the sector into the future.

Since the establishment of the Department's last Electric Plan in 1994, the industry has been transformed. Ten years ago, wholesale energy was centrally dispatched based on costs. Today, there is a competitive wholesale market for electricity with dispatch determined by the bid-in prices. Area specific market-clearing prices rather than generator costs now form the basis of market settlements between buyers and sellers.

At the retail level all of the neighboring states in the region have moved to retail choice. Vermont's electric sector remains a vertically integrated monopoly environment.

Major challenges ahead include the replacement of major power source contracts representing roughly two-thirds of the Vermont energy mix in the period from 2012 and 2015. Many individual Vermont electric utilities face major resource decisions even sooner. Steps taken today by the State, Vermont utilities, and other stakeholders today will create opportunities for addressing tomorrow's challenges.

Vermont is already confronting major decisions in relation to transmission and distribution constraints in the state. Ten areas of the State have been identified as constrained areas and are the subject of investigation. Continued growth in the Northwest region of the State will likely continue to present fresh reliability challenges in the next decade. Addressing those challenges in a least-cost manner may require an early understanding of the potential transmission solution so that both generation and efficiency services may provide a portion of the solution.

A Chapter-by-Chapter summary of the Plan is provided below.

Chapter 1 -- Charting Vermont's Electric Energy Future

This Chapter establishes the guiding principles and goals for this Plan and the resulting actions of Vermont utilities, the State's Energy Efficiency Utility, regulators, and other stakeholders and industry participants. In order to be in compliance with the *Electric Plan* and for determination of compliance with 30 V.S.A. Section 202(f), 248(b)(6), and other statutes, utilities must follow the provisions of Docket 5270 and other Board Orders as well as Appendix A of this Plan.

Subsection 202(b) of the Statute establishes that this Plan *shall serve as the basis for electrical energy* *policy* based on the lowest present value life cycle costs, including environmental and economic costs.[1]

Electric policy in Vermont is part of a State Energy Policy, which requires,

…to the greatest extent practicable, that Vermont can meet its energy service needs in a manner that is adequate, reliable, secure and sustainable; that assures affordability and encourages the state's economic vitality, the efficient use of energy resources and cost effective demand side management; and that is environmentally sound.[2]

Chapter 2 -- Context for Vermont's Electric Energy Planning

Over the last decade, the industry has been transformed at the wholesale level to a competitive market. Current wholesale market conditions can be characterized by significant price volatility, a heavy dependence on fossil fuels and associated price volatility, and substantial capacity (or overcapacity) in relation to the underlying New England load.

In the mid-to-late 1990s, Vermont, along with many other states considered a move to retail choice. State initiatives during that period were predominantly focused on states and regions with high retail electric rates. In the end, some 17 states opened their markets to retail choice, including all of our New England and Northeast neighboring states. In certain states, the reforms were complete failures, characterized by volatile wholesale and retail prices, bankruptcies, and, ultimately, suspended. Other states have had a more positive experience. However, the base of experience from which Vermont can draw is still fresh and evolving.

Amidst these changes, Vermont remains a vertically integrated regulated monopoly. There are currently 21 electric distribution companies. Four of these companies are investor-owned companies, two are electric cooperatives (ratepayer owned) and the remaining 15 are municipally-owned and operated, including Burlington Electric Department. In addition to the 21 electric distribution companies, Vermont has one bulk transmission company (VELCO) that is wholly-owned by Vermont's electric distribution utilities. VELCO currently owns and operates 534 miles of transmission lines, 25 substations, and a 200 MW HVDC converter.

Other important institutional features of the existing environment include: the Vermont Public Service Board, which regulates Vermont's electric distribution companies and the sector; the Department of Public Service, which is charged with public advocacy and the development of this Plan; the small independent power producers and VEPPI (their purchasing agent); the State's Energy Efficiency Utility; and the Vermont Yankee Nuclear Power Station in Vernon.

Vermont does not operate as an island, but is connected to a regional power pool that is operated and managed by a regional entity, currently the Independent System Operator for New England (ISO-NE), but soon to be transformed to the Regional Transmission Organization for New England (RTO-NE). The regional grid and markets ultimately fall under the jurisdiction of the Federal Energy Regulatory Commission (FERC).

[1] 30 VSA 202(b) and 218c
[2] 30 VSA 202a

Chapter 3 -- Current and Forecasted Demand for Electricity

On a statewide basis, historic demand for electricity grew at a pace of almost 4% annually from 1977 through 1989. During the decade from 1990 through 2000, the growth in electricity demand slowed to a rate of growth of about 1.5% annually. Recent patterns show even slower growth. From 2000 to 2003, the pace of sales growth in electricity demand had slowed to an annual rate of about 0.3%.

Growth in peak demand has remained fairly steady in relation to winter peak, but the summer peak has grown rapidly. In 1990, the winter peak was approximately 1,000 MW. On December 20, 2004, Vermont achieved a new peak of 1,086 MW, surpassing the January 2004 peak of 1043 MW. Vermont's summer peak was only 805 MW in 1999. By the summer of 2002, the summer peak temporarily exceeded the winter peak reaching a high of 1,023 MW.

Electric load growth in the State has substantially slowed in recent years and growth in electric energy demand is projected to continue at a pace of roughly 1% for the coming 20 years. Peak demand should keep pace with energy demand. Wholesale electricity prices are expected to decline slightly in the next few years before returning on a gradual incline over the term of the Plan. Considerable uncertainty in the underlying direction of wholesale natural gas prices will continue to affect the regional wholesale price of electricity in New England.

Chapter 4 -- Existing Supply Resources and Policy Issues

Vermont currently enjoys a stable long-term supply mix. Vermont utilities have fixed commitments from Hydro Québec (HQ) and Vermont Yankee (VY) that supply about two thirds of the energy used in the state. Roughly 15% of the electricity in Vermont comes from small renewables (less than 80 MW), including biomass, wind, hydro, landfill methane, and now farm methane. Therefore, including Hydro Quebec, roughly half of the State's energy comes from renewable sources. Less than 20% of our energy is tied to fossil fuels. As noted earlier, the bulk of our current commitments are not due to expire until the period between 2012 and 2015.

Chapter 5 -- Emerging and Sustainable Energy Technologies

The volatile nature of wholesale energy prices, driven in large part by underlying fossil fuel price volatility and concerns for the environmental cost of traditional energy sources, has created ever increasing emphasis on the need for the region to diversify away from traditional large central power stations, especially those fueled by fossil fuel sources. While Vermont's own mix is stable, there is mounting recognition throughout the region on the need to develop a more sustainable portfolio of sources in the region.

Chapter 5 describes current technology initiatives in Vermont, including efforts to develop more wind, landfill methane, and solar energy, among other sources that may be commercially viable even in the current environment. Sustainable technologies include both utility-scale projects, and smaller scale generation that can be cost-effective for consumers when coupled with grant programs and net metering.

There are a wide variety of mechanisms for stimulating the development of sustainable energy technologies, such as: portfolio standards combined with tradable credit programs; grant funded mechanisms; tax incentives; ratepayer funded mechanisms like net metering; and voluntary programs, such as the CVPS Cow Power™ program.

Northern New England, with its ample forests, windy ridge-tops and numerous rivers would appear to have an advantage over other New England states in their ability to produce renewable energy. This fact should not be lost on policy makers. It is likely that the three northern New England states could host a large share of the renewable resources necessary to meet the needs of the region. Further, Vermont has a significant number of renewable energy based businesses with the ability to serve a developing market for both residential and utility sized applications.

Vermont can play an important role within the region by complementing neighboring initiatives to promote sustainable electric energy. In the shorter term, Vermont seems likely to play an important role in helping to meet regional demands for sustainable electric energy through tradable credit programs in connection with state portfolio requirements and green pricing. With growth in new loads and as major source contracts begin to expire in 2012, Vermont should continue to provide its role as a responsible regional neighbor and meet an appropriate share of its own needs through sustainable energy sources. These efforts can be complemented by continued efforts to promote the development of smaller-scale sources in connection with tax-incentives, targeted grant funding, voluntary ratepayer programs, and ratepayer supported mechanisms like net metering.

Chapter 6 -- Demand Side Management, Energy Efficiency, and Conservation

The Department of Public Service has worked through a variety of mechanisms to ensure the development of cost-effective energy services. Included among the many programs and initiatives are building standards and guidelines, state and regional pricing initiatives, targeted demand-side-management programs, and system-wide DSM programs that remain the responsibility of a statewide entity known as the Energy Efficiency Utility (EEU).

The EEU's total expenditures during the first three years of operation were $25.4 million, which resulted in 101.6 thousand MWh savings in generation annually over an average 14.5 years.[3] This means the average EEU cost per kWh is 2.8 cents. As a comparison, the average cost of wholesale market power in New England in 2002 was about 3.6 cents per kWh. Today, the average cost of wholesale market power is roughly 5.7 cents per kWh. Amidst the success, some argue that even more money can be spent to save electricity through the EEU.

Despite the success of the EEU, it remains important for both ratepayer interests and supporters of the EEU that concerns of the EEU's skeptics be adequately aired and that all issues associated with savings claims, rate impacts, and ongoing program emphasis continue to receive an ongoing vigorous review. This is no different from any other ratepayer funded utility program. Uncertain savings measurement and ratepayer equity concerns distinguish EEU programs from other utility services that can be directly metered and applied to ratepayers in proportion to services rendered. The Plan recommends institutionalizing broader involvement and/or better outreach among all those concerned with savings calculations and program design of the EEU.

Rate impacts are important to better understanding the degree to which non-participants are affected by EEU programs. Higher rates, resulting from the funding of EEU programs, can serve to exacerbate equity concerns associated with the EEU. Additionally, higher wholesale energy prices in certain areas of the state may be better targeted by the EEU to benefit all ratepayers in the State. The Plan recommends a thorough analysis of rate impacts that give due consideration to include all "system benefits". The Plan also recommends that T&D constrained areas are adequately addressed in

[3] The EVT amounts here include the Customer Credit Program results.

development of efficiency programs by the distribution utilities and the EEU.

Energy efficiency programs are designed to target end uses and savings opportunities up to the level of avoided costs. Estimates of avoided costs, however, can vary over time and can vary significantly in constrained areas. As noted above, avoided costs can be higher in constrained areas. Current estimates of avoided costs are old and require updating. The DPS and stakeholders need to ensure that these costs are periodically reviewed on a timely basis and reflect appropriate differentiation for geographically constrained areas.

Finally, proper planning and decision-making requires a closer integration of distribution utility activities with activities of the EEU. Distribution utilities can help inform the EEU priorities and planning by highlighting areas where earlier intervention can reduce the burden to ratepayers. The distribution utility may also rely on the EEU for additional services to meet the DU's own obligations for delivery of programs beyond the system-wide programs that are the EEU's responsibility. Additionally, the EEU can help prepare the distribution utilities to better understand the impacts of efficiency programs on current and future load.

Chapter 7 -- The Bulk Power Transmission System and Standard Market Design

On August 14, 2003, large portions of the Midwest and Northeast United States and Ontario, Canada, experienced an electric power blackout. The outage affected an area with an estimated 50 million people and 61,800 MW of electric load in the states of Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, New Jersey and the Canadian province of Ontario. The blackout began a few minutes after 4:00 pm Eastern Daylight Time (16:00 EDT), and power was not restored for four days in some parts of the United States. Parts of Ontario suffered rolling blackouts for more than a week before full power was restored. Estimates of total costs in the U.S. range between $4 billion and $10 billion (U.S. dollars).[1]

Providing reliable electricity is an enormously complex technical challenge, even on the most routine of days. It involves real-time assessment, control and coordination of electricity production at thousands of generators, moving electricity across an interconnected network of transmission lines, and ultimately delivering the electricity to millions of customers by means of a distribution network.

Vermont's high voltage transmission system (lines rated 115kV and above) is about 540 line miles. Vermont's transmission system is an integral part of the power delivery network in New England, which in the past decade has undergone significant changes in the pricing and provision of transmission service. There are major regional initiatives that are proposed or underway which will influence planning methods and decisions for selecting new transmission and supply resources in Vermont. The Plan addresses Vermont's bulk power delivery system in the context of these structural changes.

Vermont's current contracts with HQ also have important implications for the reliability of Vermont's transmission system. Presently, system reliability at high load periods requires the flow of at least 200 MW from HQ over the Highgate interface into northwest Vermont. If these current contracts and the associated flows through Highgate are lost, a need would be created for either additional transmission investment, significant new generation in the northwest portion of the state, or specific wheeling and contractual arrangements designed to keep this interface active.

Transmission is integral to the State's long term plans not only for reasons of network reliability, but also for providing Vermont options for replacement power supplies when existing contracts expire. Already, ten areas of the state have been identified as areas where local distribution and/or subtransmission, and possibly high voltage transmission systems are or soon will be unable to reliably serve area load. Under this Plan, the Department proposes that VELCO prepare a long-term network expansion plan that will serve to identify long term transmission needs. Such a plan will help assure the least cost delivery of electricity services. The network expansion plan will serve as the foundation from which Vermont's electric distribution companies and VELCO will be asked to acquire the combination of efficiency services, traditional generation, distributed generation, and/or T&D upgrades necessary to deliver service at the lowest cost.

Chapter 8 -- Resource Planning and Decision-making

Under 30 V.S.A. '218c[4] each regulated electric or gas company is required to prepare and implement a least cost integrated plan for provision of energy services to its Vermont customers. Public Service Board (PSB) Orders, beginning with Docket 5270, define requirements that a utility's complete Integrated Resource Plan (IRP) should meet in order to pass the Department of Public Service (DPS) review and comply with the PSB's approval requirements. Appendix A of this Plan establishes the detailed requirement for electric utility IRPs.

Resource selection does not begin and end with the processes and standards of integrated resource planning. Rather the planning process is an ongoing decision-making process. Under IRP, decision-making must be least cost. However, the framework for determining what is in fact least cost must account for the uncertainties and multiple contingencies. Chapter 8 and Appendix B highlight a decision-making framework for addressing uncertainties and multiple contingencies.

A particularly challenging area for decision-making is in its applications to developing resource solutions to meeting capacity requirements in local areas. This is known as Distributed Utility (DU) planning. The choices involved can include a variety of resource types, typically comparing local generation and Demand Side Management (DSM) against traditional central station generation and transmission and distribution infrastructure. Appendix F of this Plan provides the guidelines that cover DU planning.

[4] 30 V.S.A. § 218c. Least cost integrated planning
(a)(1) A "least cost integrated plan" for a regulated electric or gas utility is a plan for meeting the public's need for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs.
(2) "Comprehensive energy efficiency programs" shall mean a coordinated set of investments or program expenditures made by a regulated electric or gas utility or other entity as approved by the board pursuant to subsection 209(d) of this title to meet the public's need for energy services through efficiency, conservation or load management in all customer classes and areas of opportunity which is designed to acquire the full amount of cost effective savings from such investments or programs.
(b) Each regulated electric or gas company shall prepare and implement a least cost integrated plan for the provision of energy services to its Vermont customers. Proposed plans shall be submitted to the DPS and the PSB. The PSB, after notice and opportunity for hearing, may approve a company's least cost integrated plan if it determines that the company's plan complies with the requirements of subdivision (a)(1) of this section.

Chapter 9 -- Designing Resource Portfolios for 2015, 2025 and Beyond

Similar to the prior electric plans, the current Plan presents only hypothetical resource plans showing possible future resource mixes. This plan does not and cannot prescribe a specific electric supply portfolio for Vermont utilities. The electricity market is complex and ever changing. Utility managers are expected to develop a sound decision-making framework that assures sound planning and decision-making at the time that decisions can or must be made. This Plan established the framework for sound decision-making by utility managers in this complex environment. Nevertheless, the Plan presents an illustration of a potential future resource mix based on a collaboration of industry participants and stakeholders in a workshop.

Today, Vermont's electric portfolio is heavily concentrated in just two resources: Hydro Québec (HQ) and Vermont Yankee (VY), which supply two-thirds (about 600 MegaWatts (MW)) of the state's peak electricity demand. Specifically, for 2002, the electricity sources were 34% Nuclear, 32% HQ, 13.5% System (Market), 6.5% DSM, 6.4% Small Hydro (Instate), 4.6% Other Renewables, 1.5% Oil and 1% Gas.

The collaborative mix in 2015 presents a mix comprised of 7% Connecticut River Hydro, 3% onsite generation, 15% DSM, 35% "instate" resources, and 40% "market" purchases. For 2025, the collaboration revealed a resource mix comprised of 5% Connecticut River Hydro, 2% Solar, 3% Onsite, 20% DSM, 35% Market, and 35% Instate.

Chapter 9 also begins to define the steps that will need to be taken by utilities in the future to obtain the electric portfolio that Vermont will need in 5, 10, and 20 years from now. There are a number of concrete steps that can be taken to begin to address Vermont's future energy needs.

Chapter 10 -- Strategies to Control Electric Costs and Action Plan

Access to affordable electricity is a concern for all classes of electric ratepayers. Vermont rates are over 50% above the national average. Within the region, Vermont is more competitive but remains above the regional average by roughly 9% for residential customers, about 5% for commercial customers, and, on a statewide average, less than 1% for industrial customers.

Some aspects of our costs are beyond our ability to directly control. Vermont and other states in the region do not enjoy access to low cost energy sources that are available in many other parts of the nation, in part due to low cost federal power projects. Nevertheless, there are areas where Vermont has some control over our costs and an ability to remain competitive within the region, and, given our other advantages, remain competitive overall. Areas where we may be able to contain costs and improve the affordability of electricity services include the following:

- Effective resource selection and decision-making (See Chapter 8 for a full discussion of this category);
- Energy portfolio diversification (See Chapter 9 for a full discussion of this category);
- Alternative performance-based regulation systems and benchmarking;
- Regulatory clarity;
- Efficient rate designs;
- Low-income electric assistance;
- Retail choice (See Chapter 2 for additional information on Retail Choice);
- Public-private partnerships to secure low-cost electric supplies;

- Utility consolidations; and
- Buy down of QF contracts.

Over the next twenty years, the electric industry will continue to evolve in ways that appear likely to defy prediction. Over the short run, the industry is poised for new challenges presented by a cascade of wholesale market reforms. Ongoing policy and regulatory reforms within the region, changes in market design, and the uncertain wholesale market now predominate in a sector long understood to be stable and reasonably predictable.

Vermont must establish strategies and actions that reflect Vermont values, while accepting the realities of change in front of us. The strategies and action plan presented below represent ways of advancing Vermont's values in the face of changes and market uncertainties ahead. In light of current circumstances and the changes highlighted here, the following priorities and actions are recommended in this Plan.

- Diversification -- Electric utilities need to begin the process of planning for the replacement of major power sources that are due to expire in the next decade. Vermont can begin that process by expanding the pool of potential opportunities now.
- Lower Costs -- Vermont has high rates and high electric costs. Vermont ranks poorly in relation to both the nation and the region in the rates for electricity. High rates present a challenge for businesses that depend heavily on electricity and compete globally. High costs also present challenges for low-income families.
- Clean Energy -- Vermont places high value on sound stewardship of the environment. For this reason, its electric plan should promote the establishment of an ongoing clean source mix.

In addition to the priorities listed above, the state should undertake a list of studies and actions identified in each of the sections of the Plan. The Department intends to embark on future planning and stakeholder activities to further define and develop the policies and programs highlighted above, and to address the challenges of replacing existing sources in the next decade.

CHAPTER 1: Charting Vermont's Electric Energy Future

INTRODUCTION

The *Vermont Twenty Year Electric Plan 2005* lays out the State's long-range goals for electric energy and analyses from a statewide perspective of the current status of the State's electric utility industry and the primary factors that may influence it over the planning horizon. Strategies and recommended actions are also set out in this Plan, along with a set of guidelines for utility Integrated Resource Plans (IRPs). After assessing recent historic information about Vermont's electric energy use, combined with analysis of economic, social, and industry trends and legislated state policies for utility service and energy matters, the DPS adopts this Plan for directing its own actions and as Vermont’s policy document for electric utilities.

In addition to presenting policy, recommendations, and general direction, the Plan presents several hypothetical plans that the state could follow in order to meet anticipated demand for electric energy over the planning horizon at lowest societal cost. In order to be in compliance with the *Electric Plan* and for determination of compliance with 30 V.S.A. Section 202(f), 248(b)(6), and other statutes, utilities must follow the provisions of Docket 5270 and other Board Orders as well as Appendix A of this Plan.

The *Electric Plan* becomes the electrical energy portion of the State’s comprehensive *Energy Plan.* Completion of the *Energy Plan*, will follow the development of the *Vermont Twenty Year Electric Plan 2005.*

THE PLANNING PROCESS

The preparation of this Plan began in 2001 with two public meetings in Montpelier. Subsequently in June and August of 2002 the DPS issued information requests to Vermont’s electric utilities to gather input on their issues and concerns related to the development of the fourth edition of the Plan.

It is important to note that this process was conducted against a backdrop of uncertainty and turmoil in the electric markets. The electric industry restructuring experiment was being severely tested in California. Energy companies were entering into bankruptcy proceedings and their executives were facing indictments. In New England the wholesale energy market rules were, and are, continuing to undergo transformation. The playing field and the rules of the game were and still remain in a state of change. Against this background the DPS released a Draft Plan in December of 2003.

The expiration of two key long-term sources of energy supply (Hydro-Quebec contract and Vermont Yankee) within the planning horizon adds a significant amount of uncertainty and presents a unique planning challenge. While these resources have the potential to be extended beyond their current contract life, there is a high degree of uncertainty regarding that possibility. The Draft Plan served the purpose of stimulating public interest in the process and outcome. Five well-attended public hearings were held in early January of 2004. Meetings were held to share plans with the public and gather input in Burlington, Montpelier, St. Johnsbury, Rutland, and Brattleboro. Additionally in an unprecedented action in the Department's planning process three workshops were held, one each in January, February and March of 2004. Attendees represented the entire spectrum of stakeholders. Represented were utilities, environmental groups, industry and commerce, ski resorts and members of the public.[1] This portion of the process was a useful vehicle for the exchange of information and discussion of differing points of view.

In August, the Department prepared a Public Comment Draft that was released on August 6, 2004. The Department received further guidance and comments from a variety of sources in meetings and through written submissions. The culmination of the public process is reflected in a Final Draft. The Final Draft was released on December 3, 2004. Hearings on the Final Draft occurred on December 14, 15, and 16 in Brattleboro, Burlington, and Montpelier. During this same period, the Department received comments on the Plan from dozens of groups and individual members of the public, environmental organizations, renewable technology advocates, private utilities, utility cooperatives, the EEU, staff of the Public Service Board, and VELCO staff.

In addition to input from interested parties and the public, Vermont's energy planning is based on research and modeling. In order to plan for meeting the State's future electric needs, the Department developed load forecasts.

The Department's analysis has been prepared on a statewide basis. Findings in the base case and alternative cases are presented here and recommended for the State's utilities to consider in the preparation of their respective Integrated Resource Plans (IRPs), although load forecasts, supply planning and IRPs developed by each utility must be based on analysis of what is cost-effective for the utility's specific customer base and distinct operating situation.

This Plan is an effort to reflect and guide electric resource plans based on well-established goals for Vermont's electric energy planning and statutory requirements. Within this framework for the State's electric energy planning, the Department has developed demand forecasts, assessed Vermont's current situation, and highlighted potential resources and supporting policies to meet future needs. The State's supply-side resources and demand-side resources (those currently available and those that are likely to be available in the near future) have been investigated. Certain transmission and distribution improvements that will help enable the state to meet its long-term goals are also presented. Resources for meeting the State's base case and alternative cases are presented along with a set of recommended actions that can serve as a guide for decision making by the Department, utilities, state government, and energy policy makers.

In addition to presenting policy, recommendations, and general direction, the Plan presents several illustrative strategies that the state could follow in order to meet anticipated demand for electric energy over the planning horizon at lowest societal cost. This effort was in response to significant concern expressed by stakeholders and the public regarding the expiration of the HQ and VY contracts. In preparing these alternative plans, long term statewide demand and inventories of current and potential resources that could meet the State's electricity needs over the long term were identified.

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[1] Attendees: Agency of Natural Resources, Associated Industries of Vermont, BED, BERC, CA Efficiency, CVPS, Energy Project, EVT, GMP, Grimason, IBM, Kassel Saunders, Nonse Associates, Orleans Electric, Pace Law School, PSD, REV, Shems Dunkiel, Sierra Club, Stratton Mountain Resort, Sugarbush Resort, UVM, VEC, VEIC / EVT, VEPPI, VGS, VLA, VNRC, VPPSA, VPIRG, VSAA, VT Chamber of Commerce, VT Forest, Parks, WEC, and members of the public.

These resource portfolios will also vary with the passage of time, circumstance, changing fuel prices, and technological changes in existing and emerging supply and demand-side technologies. In order to be in compliance with this *Twenty Year Electric Plan* and for determination of compliance with 30 V.S.A. Section 202(f), 248(b)(6), and other statutes, utilities must follow the provisions of Docket 5270 and other Public Service Board Orders as well as Appendix A of this Plan.

ROLE OF THE PLAN AND THE DEPARTMENT'S PLANNING

This Plan and the Department's planning initiatives attempt to further the goals and direction established in legislation. As it was framed in last update to the plan, the planning role of the Department is as follows:

> Planning at the Department provides information and guidance to Vermont utilities, other decision makers, and the General Assembly; establishes a standard of planning and performance for utilities; and supports and guides Department actions in public advocacy and the purchase and sale of power.

The Plan itself is an instrument of the legislature designed to help guide utilities and the state to operate in a coordinated manner consistent with legislated goals and a supportive regulatory and policy environment. The Plan guides the Department's own advocacy before the Public Service Board and informs utilities on regulatory matters.

This Plan does not attempt to prescribe specific resource decisions for utilities. The utilities themselves are ultimately responsible for making sound resource decisions at the appropriate time and for ensuring that the commitments made adequately account for potential uncertainties and contingencies that may arise. The dynamic nature of energy markets, including technology change, volatile fuel prices, and uncertain user demands dictate timely and responsible decision-making from managers that closely monitor the situation. This Plan defines some of the planning and decision-making processes that utility managers should undertake to ensure sound decisions in a complex and changing environment.

AUTHORITY VESTED IN THIS PLAN

This 2005 edition of the Plan supersedes the previous versions as the standard by which the DPS measures Vermont utility actions in all matters that may come before the Public Service Board (PSB) for determination of consistency with the State's electric energy plan, for determining whether a utility's filed Integrated Resource Plan (IRP) should be approved, and for the standard of being consistent with the "general good of the state."

VERMONT ENERGY AND ELECTRIC POLICY

This Plan is guided by and conforms to the goals of energy and electric policy as contained in Vermont Statutes.

Electric policy in Vermont is part of a State Energy Policy, which requires,

> *…to the greatest extent practicable, that Vermont can meet its energy service needs in a manner that is adequate, reliable, secure and sustainable; that assures affordability and encourages the state's economic vitality, the efficient use of energy resources and cost effective demand side management; and that is environmentally sound.*[2]

Subsection 202(b) of the Statute establishes that this Plan *shall serve as the basis for electrical energy policy,* but based on the lowest present value life cycle costs, including environmental and economic costs.[3]

Consistent with the statute, the Plan attempts to meet Vermont's electric energy needs in a manner that is efficient, adequate, reliable, secure, sustainable, affordable, safe, and environmentally sound, while encouraging the State's economic vitality and maintaining consistency with other state policies.

There are complex interactions among these policy goals. With the exception of public safety and reliability, which takes some precedence, the objectives must be carefully balanced so that there is steady and systematic progress toward attaining them, individually and collectively. This Plan also includes guidelines, and recommendations, all aimed at directing progress toward an overall set of strategies and actions. As the State's electric utilities renew their long-range planning efforts, incorporating objectives, goals, guidelines, and recommendations from this Plan, the state can move closer to achievement of these overall goals.

EFFICIENT electric energy service is an objective of Vermont's energy planning process. Improved efficiency leads to reduced energy costs, enhanced environmental quality, and improved security. Energy efficiency does not mean reduced comfort or convenience, but achieving the same or greater comfort, productivity, or other useful result while using less energy and minimizing waste.

ADEQUATE electric energy service means that there is sufficient electric energy to meet the needs of Vermont's businesses and residents as the state economy grows and expands. To assure the adequacy of Vermont's electric energy, we must recognize that there are some energy needs for which electricity is uniquely suitable.

RELIABLE electric energy service means that consumers experience minimal service interruptions, in terms of frequency and duration, and minimal impairments in power quality. Traditionally, the focus has been on avoiding generation deficiencies or cascading transmission failure. Utilities have strived to maintain generating capacity reserves sufficient to keep the probability of disconnecting firm customers at or below an average of once in ten years.[4]

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[2] 30 VSA 202a

[3] 30 VSA 202(b) and 218c

[4] Although progress has been achieved in these areas, the biggest blackout in history on August 14, 2003 brought much of the economic activity in the northeastern United States to a halt. At 4:11pm EST, the

From today's perspective, meeting Vermont's electric energy needs in a reliable manner involves assuring that demand for power does not outpace availability and that fuel supply, demand side resources, transmission and distribution systems, and generating sources are available and functioning. In addition to managing the risks of generation interruptions, outages due to transmission or distribution system failures as well as impairments to power quality must be minimized.

SECURE electric energy service means being prepared for an uncertain future with alternative options and choices, given that neither electrical needs nor availability can be predicted precisely. The realities of global security concerns present major challenges over the planning horizon.

Vermont needs to continue promoting diversification of its resources for meeting electric energy needs. Diversification minimizes the risks associated with any single type of resource and allows the set of resources to be more easily adjusted as circumstances change. Cost-effective energy efficiency investments provide a primary resource for promoting security, establish flexibility, and give Vermont the time to adapt to uncertainties. Diversification of supply resources means not only seeking diversity of fuels and operating characteristics, but also diversity in the length and expiration dates of power supply contracts. The Vermont power supply mix must contain an appropriate balance between long-term and short-term commitments to provide for security, without sacrificing flexibility and cost-effectiveness.

SUSTAINABLE electric energy service means maintaining service and maximizing the quality of that service in a manner that is consistent with efforts to protect the quality of the environment over time. Sustainable electric energy service is both economically and environmentally viable on a continuing basis. Meeting Vermont's energy needs in a sustainable way, as called for in statute, means making a long-term commitment to maintain the appropriate contributions from renewable resources and minimizing our dependence on imported fossil based fuels and other resources that are subject to dramatic price changes and the possibility of supply disruptions.

Coordinated planning and investment in all cost-effective efficiencies can manage the need for fossil fuels, exposure to risk, and the demand for energy. However, planning and efficiency cannot generate energy or provide new sources of power for meeting the needs of the 21st century. The major energy sources that can be considered technologically viable and ecologically acceptable for the long term are renewable ones that include biomass, solar thermal, photovoltaics, wind power, and hydroelectric power. Eventually, later this century, we may be able to transition to a “hydrogen economy,” in which society’s reliance on fossil fuels comes to an end. These sources, and possibly others that become technically feasible, represent long-term options for a safe, secure, and sustainable power supply. As we make the transition to new technologies, evaluating the use of natural gas and new, cleaner coal technologies with existing and future environmental standards can be part of our strategy. The need to

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sudden plunge into darkness was a reminder of just how much we depend on electricity for much of our activities. Although Vermont did not suffer extensive blackouts, thanks in large part to the actions of ISO-NE, VELCO staff and other favorable local factors, there were only sporadic outages. The changing industry structure in New England, from the deregulation of electric markets in all New England states except Vermont, to the formation of ISO-NE and competitive wholesale power markets, has increased the complexity of maintaining a reliable transmission system, even as the importance of doing so has only increased. We envision an ongoing discussion with utility managers in Vermont and our peers across the country to implement measures to identify areas of vulnerability and to shore up grid security. We must find ways to establish a modern “smart grid” that is flexible and effectively employs distributed generation technologies.

achieve increasing amounts of source diversity, especially for baseload supply is a challenge that Vermont shares with the entire nation.

AFFORDABLE electric energy depends on the interactive relationship between energy costs and the economy. Energy costs are determined by the amount of energy used and its price. The fundamental purpose of Vermont's energy planning process is to provide electric service to consumers at the least total cost to society. Each utility must develop a complete picture of its options for providing least-cost service, supply options, and transmission and distribution upgrades while considering present and future imperatives to minimize environmental effects from power production and distribution. Implementing least-cost options is the best strategy for keeping electric energy affordable, particularly for low-income customers, and promoting economic conditions in which business can compete in a global economy and create new jobs.

Affordability is an issue of cost in relation to income. Proper pricing signals that reflect underlying cost and avoid subsidies among customer groups can encourage consumers to use electricity in a manner that is both economic and efficient. Efficient use of the resource is a key component to controlling costs and therefore in providing affordable electricity service to Vermonters. Affordability (and the resulting benefits to ratepayers and the State's economy) can be advanced both by controlling utility costs and by improving the efficiency of energy use. Both of these objectives can be advanced by sound least cost planning as provided in Vermont law. Sound, flexible rate designs can also contribute to these objectives and enhance economic vitality as well.

Vermont should continue its commitment to affordable energy by working to overcome barriers to low-income customers' participation in Demand-Side-Management (DSM) programs and further coordinating utility low-income initiatives with assistance and services available through the Community Action Agencies that coordinate the Vermont Weatherization Assistance Program.

SAFE electric energy takes into consideration protection of public health and safety when evaluating options for sources, uses, and distribution of electric energy. The range of issues and concerns associated with electric service has taken on new meaning and added dimension with the events of recent years.

ENVIRONMENTALLY SOUND electric energy supply minimizes or avoids environmental degradation. Enhancement and conservation of our natural resources and mitigation of the impact of necessary energy production and use on air, water and land are basic governmental responsibilities. Planning for future electric energy needs must also address air and water quality objectives. Vermont's energy future should be environmentally sound and strive for consistency with environmental laws and regulation at the federal and state levels.

ENCOURAGING ECONOMIC VITALITY means supporting the State's policy and plans for economic progress. Energy policy should seek out ways to reduce the price premium Vermonters pay for their electricity so as to increase economic development potential, while continuing a commitment to energy efficiency to reduce energy costs and preserve the quality of life that Vermonters value.

CONSISTENT WITH OTHER STATEWIDE POLICIES means that Vermont's energy planning in general, and this Plan in particular shall be consistent with state policies, such as the process and planning objectives of the Vermont Planning and Development Act, Act 250, and environmental and economic development policy.

In summary, the goals for the Plan embrace its statutory goals and attempt to strike an appropriate balance among its statutory ends. This Plan strives to achieve these goals by promoting a safe, reliable electric service at a competitive price.

VERMONT'S ENERGY GOALS AND RESOURCE LOCATION

The Vermont General Assembly in establishing requirements for the Department's Electric Plan established requirements for lowest-cost resource decisions. (See 30 VSA Section 202(b) and 218c) In doing so, the VGA was neither technology specific, nor bounding consideration of geographic location. Location and technology choice are decisions that should ultimately be made in a manner that is consistent with least-cost decision criteria embedded in Statute and further defined and interpreted in regulatory decisions.

The location of generation resources (or wire upgrades, or management of loads through DSM) closer to the load typically strengthens system reliability and can otherwise lead to lower costs for Vermont consumers by reducing the isolation of load pockets in constrained areas. This Plan recommends utility resource selection and encourages policies and utility practices that serve to lower system costs to satisfy such cost and reliability concerns. Offsetting consideration often requiring some balancing are the aesthetic and/or environmental impacts associated with the placement of resources close to load.[5]

ORGANIZATION OF THE PLAN

This Plan is organized into three parts:

BASIC PLANNING PRINCIPLES sets forth the fundamental goals and principles for electric energy planning used by the DPS in the regulation of, and as a participant in, the State's electric utility industry. These goals and principles, grounded in state law, PSB Orders, and sound management, provide a foundation for guiding a utility's long range planning, and the action plans developed to implement changes envisioned for the long term. Chapter 2 provides an overview of the law and relevant PSB Orders.

SITUATION ANALYSIS devotes a chapter to each of the major components of the current status of Vermont's electric demand, supply, and infrastructure. The topics covered in this section are:

- Vermont's Demand for Electricity (Chapter 3)
- Existing Supply Resources and Policy Issues (Chapter 4)

[5] Caution should be exercised in pursuing policies that are technology or location driven that are not least-cost but assert compensating development benefits. Such benefits may or may not be outweighed by their impacts on rates, reliability, local services, or environmental considerations. Most "jobs" should not in any event be valued at nominal salaried levels, but rather at additional value to the state increased salaries (all else equal). The precise location of the jobs in question, offsetting impacts on jobs from higher electric rates, diminished reliability and other complicating considerations typically result in the impact being ignored or excluded from a formal cost/benefit analysis. Similarly, added "tax" revenues must be offset by the associated demands on service.

- Emerging Technologies (Chapter 5)
- Demand-Side Management, Energy Efficiency, and Conservation (Chapter 6)
- The Bulk Power Transmission System and Wholesale Market Design (Chapter 7)

LOOKING TO THE FUTURE presents information and direction to aid in planning and decision-making in the context of the uncertainties of the next 20 years. Chapter 8 highlights the planning framework for decision-making. Chapter 9 identifies possible resource futures. Chapter 10 highlights strategies and policies designed to further goals of cost-containment and efficiency. The concluding Chapter provides recommended strategies and actions. The topics covered in this section are:

- Resource Planning and Decision-making (Chapter 8)
- Designing a Resource Portfolio for 2015 - 2020 and Beyond (Chapter 9)
- Strategies to Reduce Electric Prices (Chapter 10)
- Twenty-Year Plan Action Plan (Chapter 11)

CHAPTER 2: Context for Vermont's Electric Energy Planning

BRIEF HISTORY OF THE ELECTRIC INDUSTRY SINCE 1994

RESTRUCTURING AND RETAIL COMPETITION

Since 1994, the electric utility industry has seen dramatic change marked by prolonged periods of instability. Beginning with California, a number of states embraced retail competition. In many of those states, utilities were required to divest themselves of their generation assets, which resulted in much contentious litigation regarding the value of those assets and the utilities' "stranded costs." At the same time, restructuring of regional transmission markets also began. Not only were new wholesale market entities needed to provide a wholesale spot market for electricity, but also new rules regarding transmission system infrastructure, generating reserve requirements, and other issues associated with system reliability began to be addressed. Restructuring remains a work in progress, especially at the transmission level, as will be briefly discussed later in this Chapter and in more detail in Chapter 7.

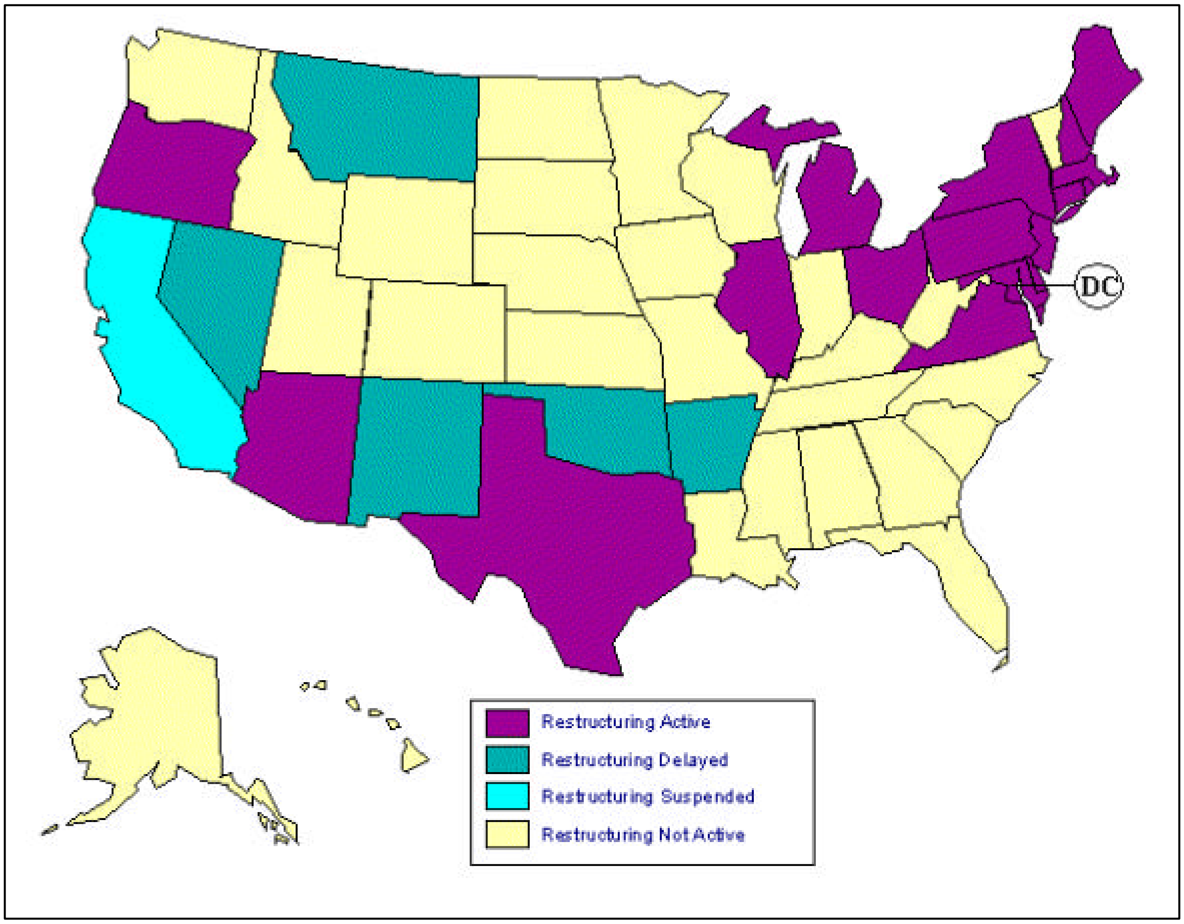
Ultimately, 17 states implemented retail choice. In certain states, the reforms were complete failures, characterized by volatile wholesale and retail prices, bankruptcies, and, ultimately, suspended. Other states have had a more positive experience. However, the base of experience from which Vermont can draw is still fresh and evolving.

Like many other states, California's initial restructuring efforts engendered a drive to implement retail competition in Vermont, which began in late 1995.

In early 1997, after years of review by state regulators and energy advocates that culminated in proposed legislative reforms, the Vermont Senate passed S.62. This bill provided a comprehensive restructuring package that established a process and plan for introducing retail choice in Vermont. The bill provided for retail competition to begin October 1, 1998, but only if the Public Service Board (PSB) determined that a set of prerequisites had been met, and had made findings on which electric services should be offered in a competitive market and which should not.

Ultimately, the House took no action on S.62. Rather, the House created a special House Electric Regulatory Reform Committee "to examine opportunities for reform in the electric industry." Although the subject was again addressed in numerous legislative proposals, no bills were voted out of the Committee. In an effort to seek further consensus and political support for restructuring, then Governor Howard Dean convened a group of stakeholders – including utilities, businesses, low income, consumer and environmental groups, the American Association of Retired People (AARP), and the Department of Public Service (DPS). That group was unable to bridge the differences between the parties on stranded cost issues.

Figure 2-1 Status of State Electric Industry Restructuring Activity - February 2003[1]



Today, Vermont's electric utilities remain vertically integrated and fully regulated entities. The wholesale market environment in which their electric utilities operate has changed and imposes new challenges for Vermont utilities and regulators. By retaining its former vertical structure, Vermont utilities also retained its pre-existing long-term contracts and resources, including Vermont Yankee and the Hydro-Quebec contract. The long term stable nature of these arrangements have served to buffer Vermont from significant immediate exposure wholesale market volatility.

BULK TRANSMISSION SYSTEM CHANGES: NEPOOL AND ISO-NE

After the 1965 electricity blackout that affected much of the eastern U.S., the federal government created the North American Electric Reliability Council (NERC). Under NERC, regional power pools were created to manage variations in electricity demand and supply, and to ensure that utilities coordinated their operations in ways that would reduce the likelihood of future blackouts. The New England Power Pool (NEPOOL) was created in 1971. It integrated the majority of New England's electric utilities and municipal systems into a tight power pool, in which individual utilities no longer independently dispatched their power supplies.[2] Instead, NEPOOL established a central dispatch

[1] Source: Energy Information Administration. http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html
[2] In other areas of the country, loose power pools were created. These power pools enforced reliability guidelines and imposed reserve requirements on member utilities that continued to dispatch their own generating supplies.

system that enhanced the region's overall reliability.

In 1996, responding to wholesale power market reforms that had begun in 1992 with passage of the Energy Policy Act (EPAct), the Federal Energy Regulatory Commission (FERC) authorized Independent System Operators (ISO). These were created to support market development of the electric power industry at the wholesale level and to ensure independent, open, and fair access to the bulk power transmission system for all wholesale electric power suppliers. In New England, the ISO is called ISO New England (ISO-NE). It serves a six-state region consisting of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.

As part of the creation of ISO-NE and wholesale power markets, NEPOOL's role was changed. Today, NEPOOL is a voluntary organization, with over 200 members who are engaged in the electric power business. Members include not only utilities, but also independent generators, other suppliers, end-users, and transmission providers including Vermont's transmission provider, Vermont Electric Power Company (VELCO).

ISO-NE currently operates under a service agreement with NEPOOL. The two organizations work together to develop market rules and operating procedures, as well as to establish transmission tariffs for New England's wholesale market. NEPOOL members make up the majority of participants in wholesale markets, provide wholesale market supplies, and buy and sell electricity on the spot market.

WHOLESALE ELECTRIC MARKETS AND ELECTRICITY TRADING

The 1992 EPAct instituted a number of changes designed to encourage development of competitive wholesale electric markets. EPAct broadened the field of entities eligible to generate and sell electricity at wholesale through the creation of Exempt Wholesale Generators (EWG), and by mandating increased non-discriminatory transmission access for such generators so they can bring their power to the market. EPAct necessitated many changes in the organization and operation of New England's transmission system, and led to the creation of ISO-NE to oversee wholesale electric markets and equal access to those markets.

Unlike most other commodities, electricity cannot be stored cost-effectively. As a result, electricity must be produced at almost the same instant it is consumed, requiring a continuous balance of supply and demand. This is why a reliable transmission infrastructure is so important; without it, this critical balancing of supply and demand on a real time basis cannot be guaranteed. In this market, generators offer quantities of electricity they are willing to sell at specific prices. At the same time, buyers, including local distribution utilities and other load serving entities, bid the maximum amounts they are willing to pay for the anticipated amount of power to be consumed. Establishing this market price provides the basis for trading and competition among participants in the wholesale market. When supplies are tight, prices increase, inducing suppliers to produce more and consumers to use less. When supplies are plentiful, prices decrease, resulting in less production and normal levels of consumption.

BILATERAL TRANSACTIONS

Although spot market transactions garner much of the publicity (headlines about price spikes,), the bulk of electric trading (about 75 % nationwide) is through longer-term bilateral transactions. These are direct transactions between wholesale buyers and sellers for market products over specified time periods and set prices. The contract between Hydro-Quebec (HQ) and the Vermont Joint Owners (VJO), which begins to expire in 2015, is one example of a bilateral contract. The sale agreement between Entergy Nuclear Vermont Yankee (VY), Green Mountain Power (GMP), and Central Vermont Public Service

(CVPS) is another example. Unlike spot market transactions, bilateral transactions can provide price certainty because their terms are not typically subject to the volatility of the spot market.[3] On the other hand, bilateral arrangements do not typically allow sellers and buyers to respond to changing market conditions.

SHORT-TERM TRADING

Short-term trading allows participants to balance loads and generation resources on a Real-Time (RT) spot market, or the Day Ahead (DA) market. Electricity supply and demand can be unpredictable, owing to factors as diverse as weather extremes or the unexpected failure of a generator. Market participants can use the DA market to hedge against additional price volatility in the RT spot market.

SPOT-MARKET TRADING

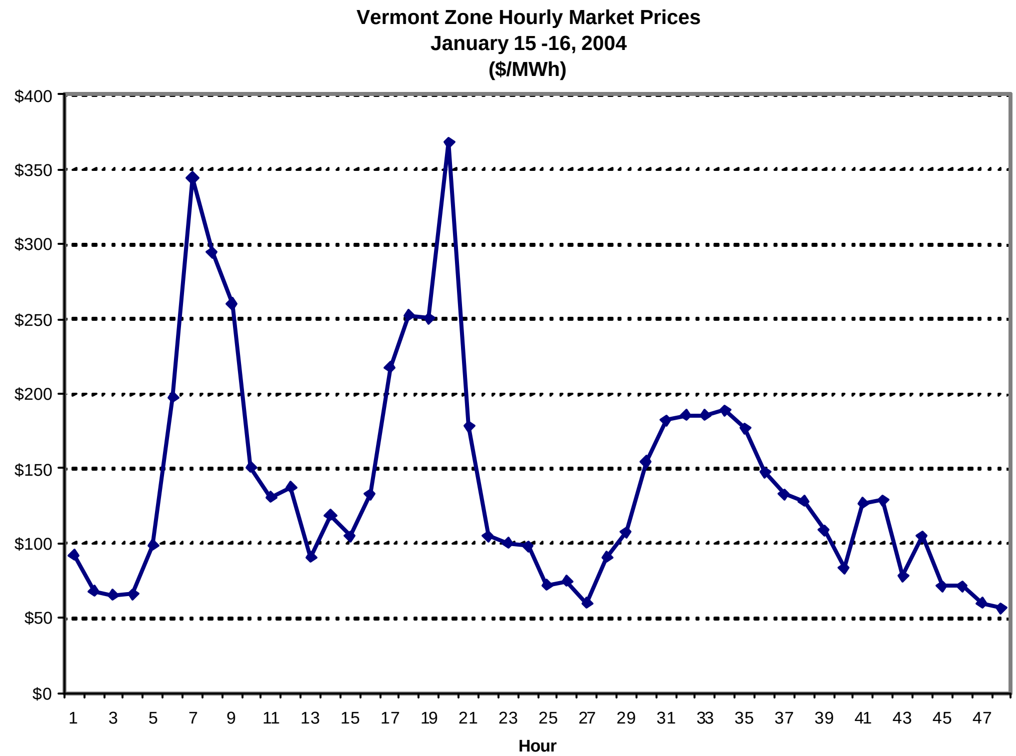
Spot trading in the RT market ensures that New England's supply and demand are balanced at all times. Generators and consumers can buy and sell in the spot market to manage risk and to account for the balance of electricity not covered in bilateral or short-term markets. However, the spot market poses the most risk for participants because prices can change dramatically in short order.

ISO-NE serves as the market clearinghouse for spot-market wholesale electric transactions. Like any commodity market, the wholesale electric market establishes a price by matching supply and demand. The clearing prices for spot market electricity, which are set every hour, are based on suppliers bidding in specific quantities of electricity at different prices (which builds a supply curve), and buyers offering to purchase specific amounts at different prices (which builds a demand curve). The point where supply equals demand determines the market-clearing price for a given hour.

Figure 2.2 presents an example of how volatile these prices can be. It shows the market clearing prices in the Vermont zone for a 48-hour period between midnight January 15 and midnight January 16, 2004. At that time, Vermont and New England were gripped in a severe cold spell. During this period, market prices varied between about $50/Mega Watt hour (MWh) to over $350/MWh.

[3] Linkage between spot prices and contract prices can also be built into the contract. The major contracts that currently exist in Vermont, however, to not have such a link.

Figure 2-2



ELECTRIC UTILITY INDUSTRY - MAJOR PLAYERS AND FORCES

Planning for Vermont's electric energy depends on the actions and cooperation of many different groups. The major players in Vermont's electric industry and their roles are briefly described below. More detailed discussions follow in later chapters for Entergy Nuclear Vermont Yankee, LLC, the new owner and operator of the VY nuclear plant (Chapter 4), the Independent Power Producers, (IPPs) who operate numerous small hydroelectric facilities and the Ryegate wood-fired plant (Chapter 4), and the Efficiency Utility (Chapters 4 and 6). Additionally, a more detailed discussion of the New England bulk power transmission system, and Vermont's transmission operator VELCO, are presented in Chapter 7.

VERMONT'S MAJOR ELECTRIC DISTRIBUTION UTILITIES

Vermont now has 21 electric distribution utilities, ranging in size from the Village of Readsboro Electric Department with 412 customers, to CVPS with 144,216 customers. Electric utilities are subject to government regulation. As regulated monopolies, the utilities can be as trustees for delivering a public service through the franchise.

A utility's existence is predicated on the Vermont PSB finding of public good and granting the utility certain rights and privileges in return for the utility's assumption of certain responsibilities and obligations. This principle applies even though many of the investor owned utilities serving Vermont have evolved from small companies, most of which were founded in the early 1900s, before the Vermont legislature fully established the PSB. (See Chapter 3 for further information on the history of Vermont utilities.)

Vermont's municipally owned utilities have been established on a slightly different legal foundation from investor owned utilities. At any time, a municipality can establish its own electric utility so long as statutory procedures for notice and voting are followed. Once a municipal utility is founded, the decisions about a fair price to be paid for the facilities that are taken over, investments in new facilities, and subsequent operations are subject to the PSB review and regulation. The third type of distribution utility, member-owned rural electric cooperative utilities, came into existence during the 1930s through the U.S. Rural Electrification Act and the Vermont Electric Cooperatives Act in order to service customers in rural areas that were not getting service from the investor owned utilities. Like the other types of regulated distribution utilities, cooperatives are regulated by the PSB and assume certain responsibilities and obligations in exchange for certain rights and privileges.

A utility's primary duty (whether publicly- or investor-owned) is attainment of the statutory goals embodied in Title 30. The “obligation to serve” is at the heart of the relationship between the state and its utilities. In return for the opportunity to earn a pre-determined rate-of-return, utilities are required to perpetually serve the electric demand within their monopoly territory. Utilities may have additional goals through their owners, public or private, subject to fulfillment of their required statutory duties and obligations to consumers.

A utility must, at a minimum, provide and carry out the planning necessary to continue providing adequate service at reasonable prices and meeting industry standards for reliability and quality of service. A reasonable price is one obtainable by diligent, effective, and efficient management, following, at a minimum, the least-cost integrated planning and other guidelines set out in PSB orders, statutes, and this Plan. Reasonable price will differ among utilities depending on circumstances, type of service area, existing supplies, markets, and available opportunities for supply or alternatives to supply.

Regulated public utilities have the right to operate as a retail monopoly, to condemn property, and to receive just and reasonable rates. The only current exception in Vermont is the DPS that has statutory authority under 30 V.S.A. § 212a to purchase electric energy from any source and to distribute and sell it at retail to all consumers of electricity in Vermont. Regulated utilities, the DPS, and facilities qualifying under federal Public Utility Regulatory Policies (PURPA) legislation, and other merchant generators can, under various provisions, sell power at wholesale to distribution utilities.

Under the current system of regulation, utilities are entitled to receive just and reasonable rates, that include a fair return on capital commensurate with the risk borne by investors. This risk is not tied solely to capital investments in physical assets. Private utilities, through a Certificate of Public Good (CPG), have been granted their franchises at little cost, but bear the risk of potential disallowance of unreasonable costs. The DPS, as public advocate, will challenge unreasonable costs associated with investments, as well as unreasonable operating expenses. It will also challenge a utility's failure to invest where needed. This highlights the importance of applying sound planning and management standards to operational matters as well as long range capital planning.

Utilities are now entitled to own unregulated subsidiaries and to designate particular goods and services to them. The unregulated subsidiaries of Vermont’s largest electric utility rent water heaters while a separate subsidiary builds wind power generation. Under the PURPA Act of 1978, utilities can be part owners of Qualifying Facilities (QF). These unregulated subsidiaries are small power generating stations that can produce up to 80 Mega Watt (MW) of power. Provisions in the 1992 Energy Policy Act (EPAct) give utilities the option to develop another type of unregulated subsidiary, Exempt Wholesale Generators (EWG), although no Vermont utilities have done so.

Although all of the other New England states restructured their electric industries and adopted retail competition, the electric utility industry in Vermont continues to be vertically integrated. With the sale of VY, Vermont utilities own little of their own generating resources. Thus, in some respects, Vermont utilities share similar characteristics to local distribution entities in other New England states.

VERMONT ELECTRIC POWER COMPANY (VELCO)

VELCO was organized in 1956 to develop an integrated transmission system to interconnect the numerous Vermont electric utilities and to provide them with access to economic power from the St. Lawrence River project. The initial 224-mile 115 kilo-Volt (kV) VELCO system was placed in service in September 1958. Since that time, VELCO has expanded its facilities and services as required by the needs of its participants and the evolution of the industry. Currently, its transmission system consists of 534 miles of transmission lines, 25 substations, and a 200 MW back-to-back High Voltage Direct Current (HVDC) Converter. VELCO is a regulated utility, owned and controlled in various percentages, by most, but not all Vermont retail electric utilities. CVPS and GMP own 86.3% of its stock, with the balance owned by 14 other Vermont distribution utilities. (See Table 2.1.)

Table 2.1 VELCO Ownership Shares

Utility	Shares	Percentage of Ownership
CVPS	34,083	56.81%
Green Mountain	17,715	29.53%
VEC-Citizens	3,544	5.91%
Burlington Electric Dept.	3,222	5.37%
WEC	420	0.70%
Lydonville	407	0.68%
Morrisville	228	0.38%
Northfield	88	0.15%
Ludlow	88	0.15%
Stowe	79	0.13%
Swanton	74	0.12%
Johnson	20	0.03%
Orleans	16	0.02%
Hyde Park	3	0.01%

VELCO operates Vermont's bulk transmission system and represents them in power pool matters with ISO-NE and in a few power purchases. VELCO also performs and directs planning, design, and construction work on the Vermont bulk power transmission system as part of the integrated regional transmission network. Their decisions on transmission line construction may affect the ability of Vermont companies to gain access to desirable power generation sources.

VELCO transmits power to Vermont's distribution utilities. Its rules allocate costs for energy and capacity requirements among Vermont utilities and greatly influence decisions made by distribution companies. VELCO tariffs and most of its operations are not directly regulated by the state, but by the FERC. Responsibility for the efficiency of the wholesale power pool within Vermont remains largely with VELCO, who is accountable for the successes and failures of that system.

VERMONT'S SMALL UTILITIES

Vermont is currently served by four relatively large electric utilities and 17 smaller utilities. In 2003, Vermont Electric Cooperative (VEC) agreed to purchase Citizens Communications Company – Vermont Electric Division (VED) that had been the subject of much oversight because of a number of accounting irregularities and disregard of PSB Orders. The parent company has been restructuring itself to focus solely on telecommunications, and has been divesting its electric, gas, and water utility divisions for a number of years. The PSB approval of the sale of VED to VEC concluded the first half of 2004. The combined entity promises savings to ratepayers through consolidation of operations, coordinated distribution system planning, and improved reliability.

Small utilities have played an important role in the development of Vermont's rural communities. They have responded to local communities needs for service in a manner that reflected the characteristics of the local communities, the customers, and the territories they have served. Questions and concerns have been raised about the future of Vermont's utilities. By national measures all Vermont's utilities are relatively small electric companies. The issue raises fundamental questions over the potential trade-offs between local control, cost and efficient and effective service delivery.

VERMONT PUBLIC POWER SUPPLY AUTHORITY (VPPSA)

Many of Vermont's smaller publicly owned utilities could not support the staff necessary to carry out certain management functions. In addition, the planning and management needs of thes e smaller utilities lacked the scope that is necessary to attract qualified applicants from these professional groups. To address the particular needs of Vermont's smaller publicly owned utilities, the Vermont Public Power Supply Authority (VPPSA) was created by 30 V.S.A. § 5011 in 1979 as a way to pool the resources of Vermont's municipal and cooperative electric utilities and obtain economies of scale for operations, planning, (including demand-side-management and least-cost-integrated planning), financing, wholesale power transactions, and other aspects of utility business.

VPPSA is also empowered under 30 V.S.A. § 5011 with broad authority to contract to buy and sell wholesale power within Vermont, as well as wholesale and retail power outside Vermont, and to issue tax-free debt on behalf of municipal and cooperative electric utilities within Vermont. VPPSA has the latitude to provide such services as may be required in support of the activities of its member municipal utilities and to market its services to non-member utilities as is deemed appropriate. VPPSA has a wholly owned subsidiary, Vermont Energy Ventures, PPC is licensed as a retail supplier in several states. As of the end of 2004, VPPSA had 14 member utilities, all municipally owned. (See Table 2.2.)

Table 2-2 Member Municipalities of VPPSA (2004)

Barton	Ludlow
Enosburg Falls	Morrisville
Hardwick	Northfield
Hyde Park	Orleans
Jacksonville	Readsboro
Johnson	Stowe
Lyndonville	Swanton

In 1992 additional legislation was passed (30 V.S.A. § 4002a) giving VPPSA authority to enter contracts to provide all requirements service, on behalf of its member systems. Under this new statutory provision member systems can now contract with VPPSA for all requirements service, enabling VPPSA to consolidate their individual loads into one large system for power supply and planning purposes. Coupled with the services VPPSA already provides, the member systems could gain many advantages as a consolidated system. Greater efficiency and economies of scale could result from preparing a portfolio of supply, Transmission and Distribution (T&D), and demand side resources that meet the long-range needs of all the member systems. In 2002, VPPSA applied to be an all-requirements provider for eight of its members, but because of a lack of agreement over certain key provisions, they ultimately withdrew their application.

In 2003, the DPS asked VPPSA to submit a combined Integrated Resource Plan (IRP) for their entire 14 utility system, so as to improve regulatory efficiency. The DPS also requested that they re-file their application to provide all-requirements service for their members, again in the interest of improved efficiency and as a way to help reduce power costs for its members.

INDEPENDENT POWER GENERATORS AND QUALIFYING FACILITIES

Vermont has a number of independently owned wholesale generators who sell power to Vermont utilities. Independent Power Producers (IPPs) are producers of electrical energy not owned by public utilities, but make electric energy available for sale to utilities or to the general public. IPPs may be privately held facilities, cooperatives such as rural solar or wind energy producers, or non-energy industrial concerns capable of feeding excess energy into the system. The majority of these IPPs are Qualifying Facilities (QF) under PURPA.

The Public Utilities Regulatory Policy Act (PURPA) of 1978 stimulated the growth of independent power in Vermont and was designed to reduce dependence on foreign oil by encouraging small generating resources using renewable resources. Prior to its passage, IPPs were rare. Section 210 of PURPA changed this by requiring electric utilities to purchase energy from certain qualifying IPPs at the utilities' avoided costs (what the utilities would have to pay, on average, for energy from other sources.) Since these avoided costs were set by regulators based on forecasts that showed rapidly rising electric prices, qualifying IPPs were able to secure high prices for the energy they produce. Currently, Vermont's IPPs account for roughly 6% to 8% of total generation and roughly seven percent of total capacity (approximately 75 MW). Vermont's qualifying facilities under PURPA consist of multiple small hydro facilities and a large wood-fired facility at Ryegate, Vermont. The Ryegate facility accounts for almost half of the total generation from Vermont's Qualifying Facilities (QF). While the IPPs have provided reliable power through the distribution utilities to Vermont consumers, they offer service at relatively high prices, which has contributed to concerns about high electric rates. In 2003, while contributing roughly 6% of the generation, they contributed over 12% to the total cost for all of the generation supplied.

ENTERGY NUCLEAR - VERMONT YANKEE (VY)

The Vermont Yankee (VY) nuclear plant is a 510 MW boiling water reactor located in southeastern Vermont. The plant first came into service in 1972. Currently it supplies about one-third of Vermont's electric energy demand. In 2002, the plant was sold to Entergy Nuclear Vermont Yankee, LLC. As part of that sale, GMP and CVPS entered into a long-term contract to buy electricity from the plant until 2012 when the current operating license expires. That contract provides guaranteed prices to the utilities each year, as well as a low-market adjuster, which will allow the utilities to pay lower prices, should the price of electricity in the New England wholesale market decline. Thus, the current contract provides a hedge against volatile wholesale prices.

In 2003, Entergy Nuclear filed a proposal with the PSB to increase the plant's generating capacity by 20%. In March 2004, the PSB gave conditional approval to Entergy for the up-rate. Conditions of approval include additional ratepayer protections, should the reliability of the plant decrease because of the up-rate, and a request that the federal Nuclear Regulatory Commission (NRC) conduct an independent engineering assessment.

EFFICIENCY VERMONT (EVT)

The DPS issued a report in May 1997 proposing the creation of a single independent statewide Energy Efficiency Utility (EEU) to deliver Vermont's energy efficiency programs. The PSB promptly opened Docket No. 5980 to investigate the proposal. After more than 18 months of litigation, delay and a preliminary PSB Order approving the EEU in concept in January 1999 the DPS, Vermont electric utilities, and other stakeholders then entered a lengthy and complex negotiation process to create the EEU.

As negotiations were under way, legislation that would clarify the authority of the PSB to create an EEU and fund it through a separate charge on customer utility bills was working its way through the legislature as S.137. That bill was passed in the spring of 1999. At nearly the same time (late April, 1999) the DPS, CVPS, and GMP filed notice with the PSB that they had reached a settlement.

Other utilities joined the settlement over the next two months; special agreements were negotiated with Burlington Electric Department (BED) and Washington Electric Cooperative (WEC) to enable them to administer programs that had the same look and feel as the seven Core efficiency programs to be run by the EEU. The PSB approved the settlement on September 30, 1999.

The DPS facilitated a transition process in which utilities prepared information and readied staff for the creation of the EEU. The DPS drafted Requests for Proposals (RFP) for the PSB use in selecting an EEU, a Contract Administrator to oversee the EEU contract, and a Fiscal Agent to collect and disburse the funds. By January 2000, Vermont Energy Investment Corporation (VEIC) was selected as the winning bidder. VEIC commenced operation of the EEU with the name Efficiency Vermont (EVT) on March 1, 2000.

In May of 2002, the DPS recommended statewide EEU budget amounts of $16.2 million, $16.3 million, and $17.5 million respectively for years 2003, 2004, and 2005, and that the VEIC contract to deliver efficiency services as EVT be extended for a second three-year cycle. The PSB, the DPS, and the VEIC negotiated a contract revision with new three-year budgets and new performance objectives for the years 2003-2005. The contract was signed by the PSB on October 31, 2002.

In October 2002, the DPS proposed a one-time reduction of approximately $2,200,000 in the projected increase of $3,000,000 in the EVT budget for 2003. This recommendation was made in response to concern expressed by certain manufacturing businesses and economic development officials that the proposed level of increase for 2003 would be difficult to absorb in such difficult economic times. In an order dated December 30, 2002, the PSB, in a split decision, agreed with the DPS October recommendation. It ordered a total of $14,000,000 be collected through an Energy Efficient Change (EEC) statewide to fund statewide efficiency services provided by EVT and BED.

On December 26, 2002, the PSB issued an "Independent Audit of Vermont Energy Efficiency Utility Energy and Capacity Savings for 2000 and 2001" dated December 20, 2002 as required under 30 V.S.A. §209(e)(12). This report verified the EEU annual energy and capacity savings estimates, as revised by the DPS, and found the programs to be highly cost effective.

ISO-NE/REGIONAL TRANSMISSION ORGANIZATION (RTO)

As part of its restructuring of the wholesale electric industry, FERC discussed establishment of regional Independent System Operators (ISO) in its Order 888. The FERC only recently conditionally approved ISO-NE to become an RTO. 106 FERC ¶ 61,280(2004) ISO NE was established as a not-for-profit, private corporation on July 1, 1997, following its approval by FERC to manage the New England region's electric bulk power generation and transmission systems and administer the region's open access transmission tariff. ISO-NE contracts with New England Power Pool (NEPOOL) to operate the bulk power system and to administer the wholesale marketplace.

ISO-NE operates a Day-Ahead (DA), hourly marketplace. Wholesale electricity suppliers and generators bid their resources into the market the day before and submit separate bids for each resource for each hour of the day. ISO-NE tabulates the bids and stacks them in dollar terms from lowest to highest, matching the expected hourly demand forecast for that hour and each hour in the next day. ISO operations staff determines the least cost dispatch sequence that reflects actual bids. Generators are dispatched to match the actual load occurring on the system, while the highest bid resource sets the market-clearing price for electricity. This market clearing price is paid to all suppliers by buyers who purchase power from the market. This differs markedly from the prior operation of the NEPOOL which dispatched plants based on their operating costs, not bid prices.

In 2002, the ISO introduced a standard market design. Under this new design, the region is differentiated in sub-regions known as "nodes" and "zones". Each such region may be subject to a separate price for electricity known as the Locational Marginal Price (LMP).

ISO-NE, guided by an independent Board of Directors, has two distinct responsibilities: operating the New England bulk power generation and transmission system facilities and maintaining the reliability of that system; and creating and maintaining a competitive marketplace. Functionally, the organization is divided into two major areas. System Operations and Reliability is responsible for the:

- Daily dispatch of electricity resources;
- Assuring reliability of the bulk power system;
- Administration of the open access transmission tariff for New England; and

- Demand forecasting and reliability planning.

The second area, Market Operations, oversees the residual wholesale electricity marketplace to ensure that fully competitive markets are created and maintained that lead to the lowest pricing for bulk electricity. It also provides customer participant services, training support, monitors the marketplace to ensure fairness to all market participants, updates ISO Rules and Procedures, as well as power exchange computer application and support services.

On November 3, 2004, the FERC conditionally approved the ISO-NE RTO Tariff, which includes provisions previously accepted by the Commission under the ISO-NE/NEPOOL arrangements. The operations date for the newly established RTO in New England is set for February 1, 2005.[4]

REGIONAL STATE COMMITTEES (RSC)

In July 2002 the FERC issued a proposed rulemaking that called for regions to implement a so-called Standard Market Design (SMD) for wholesale electricity markets across the country. The rulemaking calls for major changes to the rules and technical systems used to operate and regulate wholesale power generation, power sales and electric transmission.[5]

In March 2003, the ISO-NE implemented many of the major market rules and technical modifications required under SMD for this region. However, the governance reforms are in the process of being completed. As noted above, ISO-NE's petition to become certified as an official Regional Transmission Organization (RTO) under the terms of SMD was conditionally approved by the FERC on March 24, 2004. The operations date for the new RTO is set for February 1, 2005. FERC rulemaking recognized that states have an important role to play in regional electric system planning. Included among the governance mechanisms allowed under SMD is the formation of a Regional State Committee (RSC) to make policy recommendations to the FERC regarding such issues as system planning and expansion and resource adequacy within a region.[6]

Currently, issues, disputes, and needs related to the electric system that transcended the boundaries and legal limits of state jurisdiction are often addressed and resolved by the ISO-NE. If conflict among market participants within the region prevents the ISO-NE from obtaining support from NEPOOL and/or state utility regulators, proposed actions must be reviewed and disputes must be resolved by the

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[4] See, Notice of Operations filing with FERC, dated December 30, 2004. http://www.iso-ne.com/FERC/filings/Other_ISO/RT04-2-00012-30-04.pdf

[5] FERC, Notice of Proposed Rulemaking, Docket No. RM01-12-000, July 2002. The FERC proposed a SMD to address what it saw as persistent and costly problems in the nation's wholesale electric power markets. According to the FERC, these problems include under-investment in needed transmission, generation sited far from customers, discriminatory behavior by transmission providers against independent generators, and fundamental technical flaws in existing electricity markets. The overall goals of the design are to provide clear rules governing the wholesale electric industry and to remove market impediments to competition and economic efficiency for the benefit of customers. In the proposed rulemaking, the FERC outlined specific proposals to enhance workable competitive markets including requiring adequate infrastructure, balanced market rules, and customer protection through oversight and mitigation (of market power and market manipulation) when necessary. A final rule has not yet been proposed.

[6] The FERC White Paper discusses changes it plans to make to the original rule to address various concerns that have been raised in comments it has received since issuing it. Notably for our purposes here, the White Paper retains the commitment to approve properly constituted Regional State Committees (RCS) and clarifies its intent to vest such committees with significant authority. See FERC White Paper, April 28, 2003.

FERC. State governments within the region must then acquiesce to federal intervention in matters that are fundamentally intra-regional in nature. The FERC tries to limit its involvement in these intra-regional issues by relying on the ISO-NE to resolve them whenever possible. The significant technical expertise of a system operator allows it to go some distance toward successfully discharging this responsibility. The FERC has recognized that states within a region, acting in a coordinated way, would be better suited to address matters that fundamentally require the application of political judgment and the balancing of competing public policies. A committee comprised of representatives from each state is well suited to understanding of the implications of key electric system policy decisions on the region's producers and consumers of electricity. Such a committee also provides the necessary political accountability to rightfully make policy recommendations to the FERC on these issues.

The FERC seeks to confer authoritative influence on such a committee for several key policies related to the system. These policies include the amount and type of generation a region wants to maintain in order to preserve a reliable electric system (known as resource adequacy) and the manner in which improvements to the transmission system are considered and funded (known as system planning and expansion). In addition, the Commission has suggested that such a committee might also be vested by the states with authority to resolve disputes over the siting of inter-state transmission facilities. Other policy goals with which the committee might be concerned and advise the system operator could include but not be limited to security, fuel diversity, conservation and the environmental impacts of power generation.

The FERC has suggested a wide range of potential issues on which a Committee might recommend policy. These include, but are not limited to:

- Resource adequacy standards;
- Transmission planning and expansion;
- Interstate transmission siting;
- Rate design and revenue requirements;
- Market power and market monitoring;
- Demand response and load management;
- Distributed generation and interconnection policies;
- Energy efficiency and environmental issues; and
- Review of management and budget for system operator.

The New England Governors' Conference, Inc. (NEGC) filed a petition in June 2004 to form a RSC. This petition to form a new organization to be known as the New England States' Committee on Electricity (NESCOE) is pending at the FERC.

Initially, the NESCOE will focus on developing and making policy recommendations related to resource adequacy and system planning. It will also affirmatively investigate and report to the New England Governors on policy questions concerning the possibility of a regional authority for siting of interstate transmission facilities.

With the transition of the ISO-NE to an RTO, their responsibilities to oversee the functioning of the New England wholesale power market and the region's overall reliability have been solidified. Planning for long term supply for the region, including source diversification, remains an unfulfilled function. The intent is for the new RSC to provide a facilitative role for what is commonly referred to as resource adequacy. In translation, this effort will entail taking a long-term view of electricity needs in New England and, to the extent possible, provide proactive direction in this area.

The NESCOE will be formed as a private, non-profit corporation that will be funded out of the regional transmission tariff. While a variety of organizational issues are yet to be decided, like size of budget and staffing the pending petition calls for decisions to be made after a two-part voting screen. In order for a determination to become a Majority Determination of RSC-NE, it must pass two voting thresholds. The RSC-NE would first vote on a one-state-one-vote basis. The motion would be successful if it received the affirmative support of at least four states out of six. A second vote would be taken on a proportionate consumption basis. In this case, the threshold of support that must be met for a successful motion would be support from a percentage of regional demand equal to 99% minus the percent of the largest state's share of current demand. This latter provision would preclude one state from being able to prevent a motion from passing that otherwise had the support of five other states.

Like any voting mechanism, this one would be vulnerable to strategies that would make it difficult to obtain successful votes under both methods. For example, small states would have the potential to block a large state from taking an action that did not address their needs, while two states would have a chance to block action by the other four if they could muster a majority of the weighted votes based on their consumption. At the same time, these obstacles to success would tend to push the states to work out compromises that could obtain the necessary votes under both methods. Such actions would tend to temper the impact of a decision on a state in either minority in order to gain the necessary majority under both voting regimes. This proposed voting process would limit the occasions when the regional committee could impose its will over the objection of a particular state. This type of structure would strike a fair balance between the interests that would protect states with smaller loads (Vermont, New Hampshire, Maine, and Rhode Island) from being dominated by states with larger loads (Massachusetts and Connecticut). Likewise, it would protect states with large loads from being dominated by states with smaller loads.

THE REGULATORY ENVIRONMENT

Utility regulation, or economic regulation, serves as a proxy for competition in industries where consumers are without choice of supplier and where the services involved are recognized as essential. In the absence of competition, regulation seeks to ensure that consumers pay fair prices and receive quality service. In the competitive marketplace, where many suppliers are vying for the same consumer dollar, companies must offer competitive prices, innovative products, and quality service if they are to increase sales and earnings to the satisfaction of their shareholders. Effective regulation serves this same goal.

While the telecommunications industry is undergoing a transition towards competition and lesser forms of regulation, the electric utility environment in Vermont remains a monopoly. In both industries, regulators seek to regulate to the degree necessary to ensure the consumer is well served. Our regulated electric utilities are allowed to recover reasonable costs in their tariff rates and are provided an opportunity to earn a fair return on investment. In return, utilities are obligated to serve and offer quality, reliable service. As regulators we can ensure that prices are just and reasonable by regularly reviewing the utility's cost-of-service, or revenue requirement. Often this review can be completed by informal check while at other times a formal review takes place as part of a rate proceeding.

Several years ago at the DPS urging, the PSB began a process of bringing all energy utilities under Service Quality Reliability Plans (SQRP) that consist of critical customer service and reliability standards designed to provide a measurable definition of the statutory requirement that utilities provide a reasonably adequate service. Utilities that do not meet the standards must pay financial penalties to ratepayers through service guarantees, credits, and other mechanisms. The size and mechanics of the financial penalties differ between investor-owned utilities, whose shareholders can bear the costs of the customer rebates, and municipal and cooperative utilities, whose ratepayers themselves may ultimately pay for any financial sanctions. To recognize this difference, the DPS has been working to design SQRP for municipal and cooperative utilities that meet the goal of assuring adequate service while not penalizing the ratepayers the plans are designed to protect. As long as energy utility customers do not possess the freedom to choose another provider if they are unhappy with their service, SQRP in some form will remain an important regulatory tool.

The regulatory environment is created by regulators and utility managers together. On the one hand, utility managers must maintain a reliable electric system, make sound power purchase decisions, access capital, and provide good customer service. Meanwhile the regulators must apply their powers to protect consumers, choosing carefully how much and what kind of regulation is necessary to serve the public good without imposing an undue regulatory burden on utilities. The DPS is guided in its choices by a focus on outcomes, and concern for fostering a utility management culture that is dedicated to a constructive relationship with regulators and, more importantly, commitment to its customers. These guiding principles can ensure a stable regulatory environment, which is key to facing the uncertainties shared by utilities and regulators in the coming years.

ROLE OF THE PUBLIC SERVICE BOARD (PSB)

Under 30 V.S.A. § 3, the PSB operates as a judicial body, hearing cases on most activities of the electric utility industry in Vermont. The PSB follows precedent to lend consistency to legal interpretation and carries out its duties fairly and expeditiously. They make decisions based on the records of facts presented before them. They adopt rules implementing state or federal laws and occasionally initiates investigations. The three PSB members are appointed by the Governor through the judicial selection process for staggered, six-year terms. PSB decisions are subject to the review of the Vermont Supreme Court.

ROLE OF THE DEPARTMENT OF PUBLIC SERVICE (DPS)

According to 30 V.S.A. § 2, the DPS shall supervise and direct the execution of laws relating to public service corporations and firms engaged in such business, also known as public utilities. Primary responsibilities of the DPS include: representing the public interest in utility cases before the PSB and elsewhere; establishing goals, priorities, and standards through the *Vermont Twenty Year Electric Plan*, the *Comprehensive Energy Plan*, the *Vermont Telecommunications Plan*, planning with the state's natural gas utility, and through comprehensive energy planning, ensuring balanced resource decision-making, resolving utility consumer problems, and reviewing contracts for proposed purchases or sales and plans related to future sources of electric power. Placement of both the planning and advocacy functions in one agency has a synergistic effect, enhancing the ability of the DPS to carry out its mission.

Planning at the DPS provides information and guidance to Vermont utilities, other decision makers, and the General Assembly; establishes a standard of planning and performance for utilities, and supports and guides the DPS's own actions in public advocacy and the purchase and sale of power. The DPS does not serve as a consulting firm for the utilities to undertake their planning or to manage them. They serve to protect a utility's present and future ratepayers and to assure that ratepayers are not subjected to the consequences of insufficient or ineffective planning by utility management.

The DPS responsibilities include:

- Review and advocacy before the PSB on matters of utility rates, service quality and delivery, utility financings, plant sittings, and general supervision of regulated utilities on a range of issues before the PSB;
- Review of utility IRP;
- Handling public complaints by the DPS Consumer Affairs staff;
- Auditing of Efficiency Vermont's (EVT) activities to acquire cost-effective energy efficiency savings for Vermonters;
- Participation in specific dockets and rulemakings opened to investigate both specific and generic planning issues, applications for Certificates of Public Good (CPG) by utilities, other firms, and individuals;
- Leadership in coordinating DSM and IRP on a regional and national basis; and
- Coordination of distributed utility planning activities by electric utilities.

The DPS thus acts as a public advocate on all matters before the PSB, including matters concerning utility rates, financings, investments and provides oversight and advocacy on matters concerning DSM program implementation. The DPS also serves as a planning and policy setting body.

COMMUNICATION BETWEEN UTILITIES AND THE DPS

The regulatory process can operate efficiently only when there is clear and complete understanding among the participants. Effective communication is a most cost-effective means of preventing unnecessary litigation or expenditures on projects that will ultimately be opposed. This Plan is the DPS's effort to clarify its position on issues of utility interest.

Utilities are encouraged to discuss projects with the DPS early if there is any question as to their position. This can result in course corrections, often in every party's interest, when they are most effective and easiest to make. While the staff may not have a final answer for every inquiry, early communication can only improve the final result.

COMMUNICATION BETWEEN THE PUBLIC AND THE DPS

The DPS is the representative of the Public on matters before the Public Service Board (PSB). The Consumer Affairs unit of the DPS represents the front-line of public interaction, receiving complaints and responding to questions about utility services. In developing the Electric Plan, the DPS is responsible for holding public hearings and consulting with the Public. The DPS endeavors to find new ways of involving the public in its planning, advocacy, and other responsibilities.

The DPS role as public advocate requires that it represent the broader public interest. The DPS role at times is unpopular with individuals or localized interests. Nevertheless, the DPS continuously evaluates its responsibilities to the public and explores new ways to involving the public in energy issues and finding innovative solutions best serve the public interest.

ALTERNATIVE REGULATION

Rewards for utility performance should be designed to better align utility performance with customer requirements. Alternative regulation, also known as incentive regulation, or Performance-Based Regulation (PBR), can provide an alternative to traditional forms of regulation that can help address incentives. As described in more detail in Chapter 10, PBR may hold the potential for some constructive reforms to address such concerns with inadequate incentives. To date, alternative forms of regulation have not been employed by Vermont's electric utilities. In 2003, the Vermont General Assembly passed legislation permitting both gas and electric utilities in Vermont to be regulated under an alternative form of regulation, provided that certain standards of service and protection are included in the design of a plan.

CHAPTER 3: Current Forecasted and Demand for Electricity

THE ROLE OF ELECTRICITY IN VERMONT

VERMONT'S EARLY ELECTRIC COMPANIES

Thomas Edison's invention of the incandescent bulb in 1879 sparked a fast moving push to electrify Vermont. Within two decades of the discovery, homes and businesses were connecting to crude distribution systems in dozens of Vermont communities. At first, many of the hundreds of dams already existing along Vermont waterways were adapted to generate power. As demand for electricity grew, oil-and coal-fired generators came into use, although service was less than reliable. Floods, equipment failure, and other causes often contributed to power outages that would last for days or longer.

The advent of local power and light companies drew many players into this new industry. Gas light utilities, trolley companies, mill operators, entrepreneurs, and others were quick to join the burgeoning utility business. Legislators, impressed by the electric lights they saw while attending General Assembly sessions in Montpelier, went home to promote power systems in their own communities. Within two decades, nearly 200 electric utilities had sprung up around Vermont. Generating plants were often rated by the number of bulbs they could light. One history tells about a 300 light plant installed to serve local customers.

The burden of pumping water, sawing logs, providing light, grinding feed, and other arduous tasks were soon being performed by electricity once its labor saving qualities became known. Trolley companies retired their horses and replaced them with electric motors. Electric refrigeration made iceboxes obsolete. Many electrical uses were commonplace, some were not. Windsor Electric Light Company, (later incorporated into Central Vermont Public Service (CVPS)) reported providing the power to recharge President Woodrow Wilson's electric car in 1915 when he was visiting his summer home in Cornish, New Hampshire.

But until passage of the Rural Electrification Act of 1935, electricity consumption was low, reflecting the state’s remote, rural character, the very high cost of what electric supplies there were, and the slow process of electrification. One forthright champion of public power and rural electrification was Vermont Governor George Aiken, who continued this advocacy when he went to Washington as a U.S. Senator. By 1940, two Vermont cooperatives were operating, promising to string new lines to hundreds of Vermont farms, a goal that was achieved by 1956. During the mid-1940s, private utilities agreed to lower the cost of their line extensions by two thirds and began adding hundreds of miles of distribution line each year. Victory and Granby, with their 101 residents, were the last Vermont towns to be linked to the grid in 1963. Subsequently, through the 1960s and into the early 1970s, the price of electricity fell rapidly and consumption soared. Electric space heating, virtually unheard of in 1960, was used in over 5% of Vermont households by 1972. New appliances began to be sold and traditional appliances, such as refrigerators, were larger and more feature-laden than their earlier counterparts.

Today, electricity continues to play an increasingly important role in Vermont. Not only is electricity one of the fundamental drivers of the Vermont economy, it underlies many aspects of our daily lives, whether preserving and cooking the food we eat, or allowing us to surf the Internet. Today, electricity is ubiquitous, and most of us take it for granted. Business reliance on electricity has also increased. Vermont's ski industry, the state's largest tourism-related industry, increasingly relies on electricity for additional snowmaking, new lifts, and hotels and condominiums at slope side. IBM, Vermont's largest private employer, relies heavily on electricity for its complex manufacturing operations. Diverse industries such as banking, computer services, and even government rely heavily on electricity.

GROWTH IN HISTORIC ELECTRICITY CONSUMPTION

Vermont rode a wave of prosperity that began changing its traditional agricultural economy. New manufacturing and service industries arose, causing industrial power consumption to nearly triple to 952,000 Mega Watt-hours (MWh) between 1956 and 1976. Two major industries helped lead this growth, first, Vermont's burgeoning ski industry expanded, adding ski lifts, snowmaking operations, and real estate developments to convert Vermont to a world-class ski destination. Second, IBM, which built extensive fabrication facilities in Essex, Vermont, spearheaded rapid growth in the electrical equipment-manufacturing sector. Today it is the single largest user of electricity in the state.

When the first Organization of Petroleum Exporting Countries (OPEC) oil embargo hit in 1973, the era of cheap and plentiful energy seemed to end with it, as much of the reliance of the electric energy was generated by oil fired plants. Electric prices rose rapidly. Residential customers responded rapidly, using far more wood to heat their homes, rather than electricity and fuel oil. Customers responded by conserving electricity, lowering thermostats, and buying more fuel-efficient cars. Suddenly, energy policy was at the forefront of national issues. The federal government responded by passing a variety of energy legislation in the next few years, including the Public Utilities Regulatory Policy Act (PURPA) in 1978, which encouraged the development of independent power supplies; and the Fuel Use Act of 1978, which severely limited the use of natural gas by industrial customers. The first Corporate Average Fuel Efficiency (CAFE) standards were passed, which required that all cars sold achieve specific fuel efficiency targets. Energy conservation went to the forefront of everyone's mind, with considerable effect as consumers dramatically altered their behavior. Moreover, President Carter, who called the energy crisis the moral equivalent of war, embraced U.S. energy independence. Adding to the sense of urgency, projections of oil prices, at the time, suggested that prices would soar in the coming decades.

In Vermont, there was little that could be done directly to affect oil and natural gas use. So, its utility regulators focused on what they could control: the electric utility industry. Regulators embraced the concept of seasonal rates, requiring utilities to charge more for electricity in winter than in summer so as to encourage conservation. Utilities began to institute load control programs that allowed them to literally shut off power supplies to selected customers when demand was too high.

The establishment of appropriate price signals remains an important feature of utility efforts to manage customer power demand in the face of volatile and/or rising wholesale power price. Changes in the regional wholesale markets have lead to generally greater day-to-day price volatility due to the region's increasing dependence on natural gas. These changes have ultimately increased our exposure to sudden and dramatic increases in wholesale prices. Advances in information technologies create new opportunities for both sending appropriate price signals and allowing consumers to respond effectively to the signals sent.

Figure 3-1

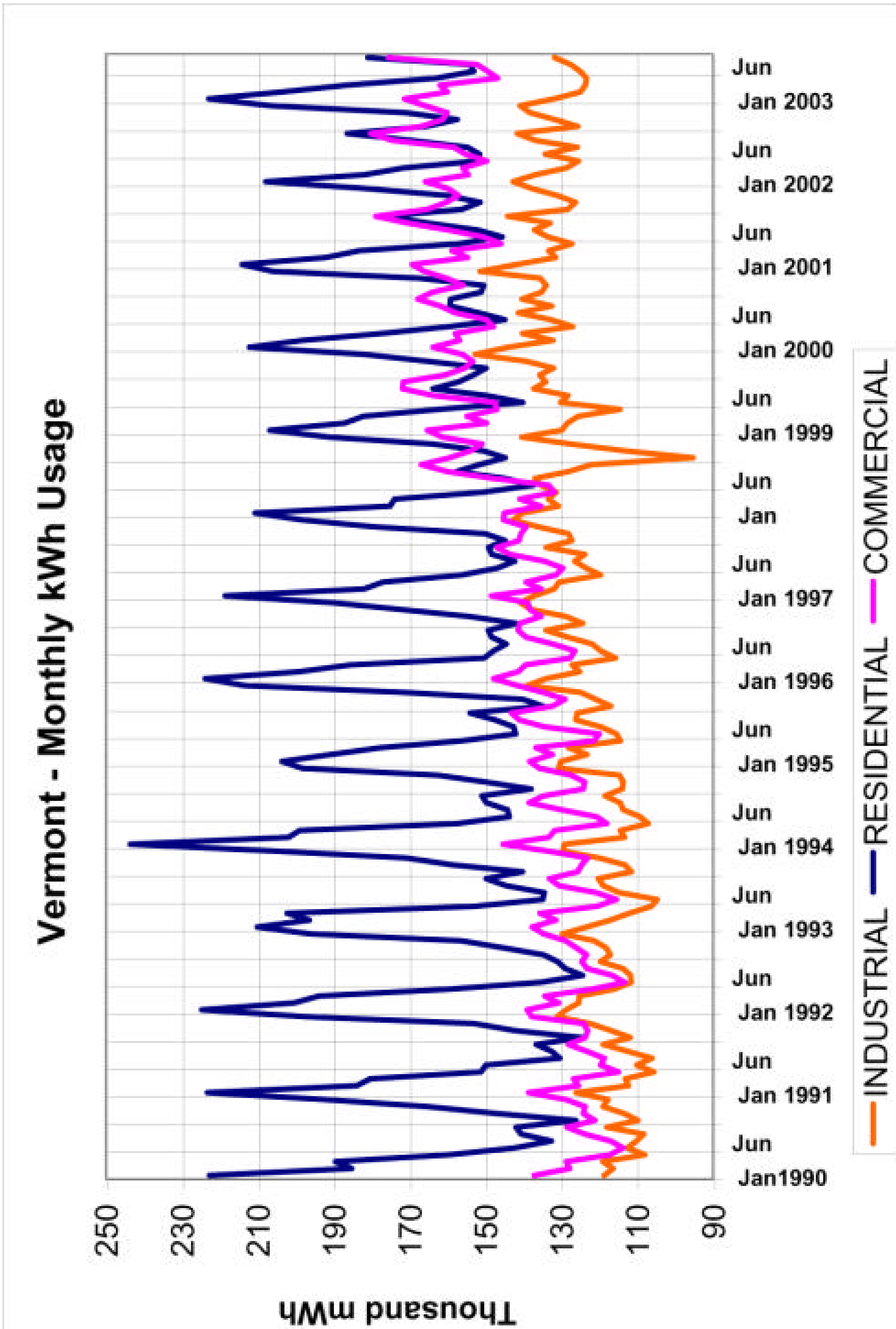
Vermont - Monthly kWh Usage
Thousand mWh
250
230
210
190
170
150
130
110
90
Jan1990
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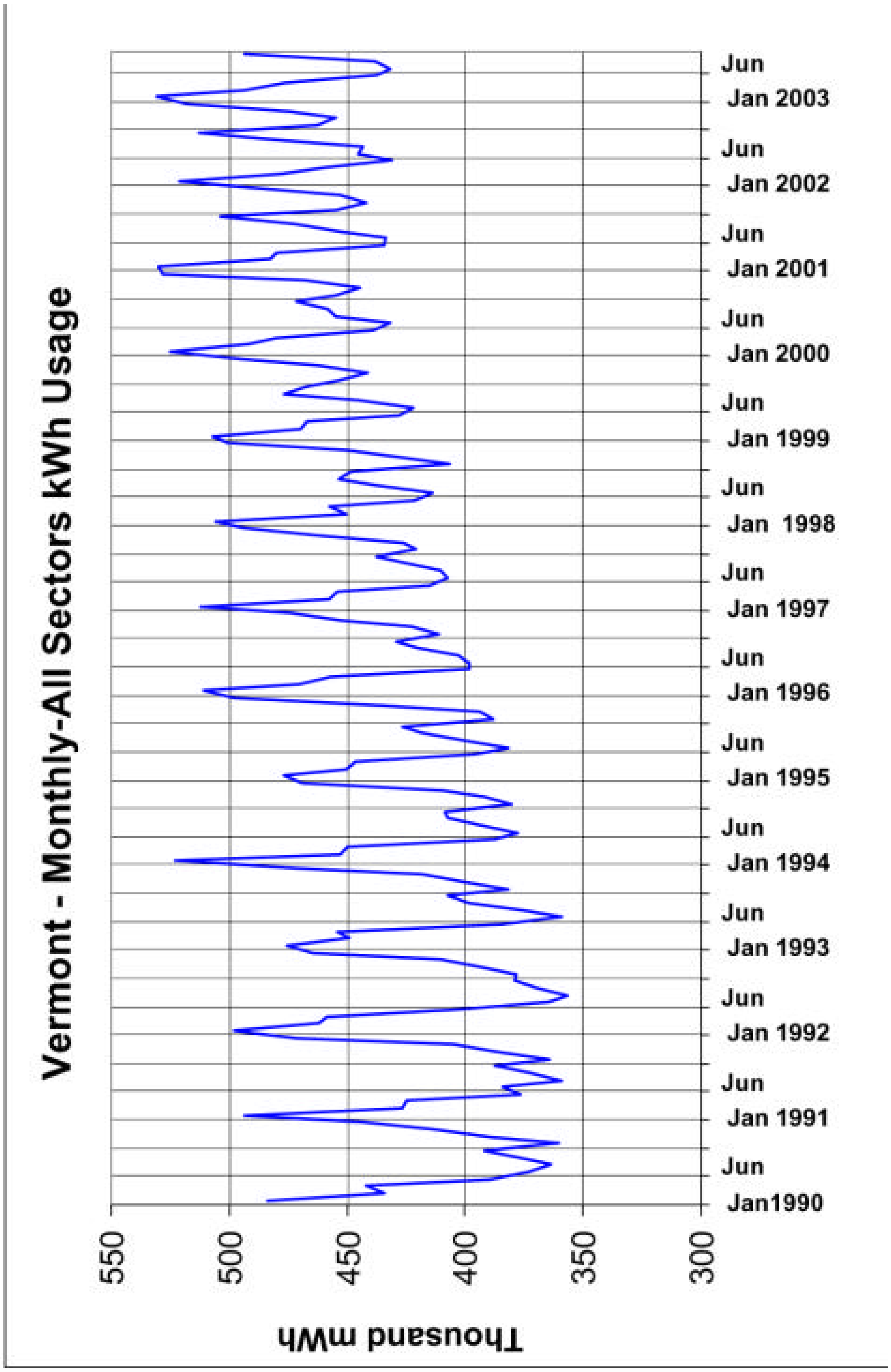
Figure 3-2



From 1977 through 1989, electricity sales again grew rapidly, increasing an average of 3.7% annually during that period. The factors affecting the growth in sales during this time were the strength of the Vermont economy, strong growth in population and household formation, and relatively constant real (inflation-adjusted) electricity prices. Commercial and industrial sales grew especially fast, averaging 4.8% annually. Residential rates grew at a slower pace, about 2.4% annually, in part because of the increase in population and household formation was tempered by improvements in energy efficiency.

Table 3-1

	Vermont Annual Electric Sales by Sector 1990 - 2003				
Year	Residential Sales (MWh)	Commercial Sales (MWh)	Industrial Sales (MWh)	Other Sales (MWh)	Sales All Sector (MWh)
1990	1,945,064	1,491,213	1,370,642	46,769	4,808,909
1991	1,904,515	1,503,791	1,386,353	47,958	4,796,650
1992	1,930,492	1,516,170	1,437,969	45,428	4,886,623
1993	1,999,721	1,531,886	1,391,148	45,087	4,924,748
1994	2,038,681	1,562,852	1,392,490	46,706	4,996,017
1995	1,973,273	1,604,645	1,484,095	42,087	5,064,008
1996	2,006,213	1,648,630	1,537,131	47,520	5,193,970
1997	1,992,280	1,674,921	1,560,517	84,428	5,229,715
1998	1,951,338	1,786,461	1,533,907	91,554	5,273,704
1999	1,998,569	1,896,439	1,587,448	44,874	5,484,455
2000	2,036,935	1,909,515	1,645,856	46,306	5,594,306
2001	2,034,191	1,930,469	1,604,272	47,098	5,570,933
2002	2,075,543	1,948,072	1,608,325	45,950	5,633,942
2003	2,128,702	1,911,512	1,561,371	41,505	5,643,089

Table 3-2 Percent Change in Electric Sales (MWh) by Sector

	Residential Sales (MWh)	Commercial Sales (MWh)	Industrial Sales (MWh)	Other Sales (MWh)	Sales All Sector (MWh)
Time Period	**Percent Change**				
1990-2000	4.72%	28.05%	20.08%	-0.99%	16.33%
1990-2003	9.46%	28.24%	13.94%	-11.26%	17.34%
2000-2003	4.57%	0.05%	-5.16%	-10.37%	0.88%

In the 1990s, growth in the demand for electricity again slowed. The recession of 1990 - 1991 hit Vermont hard. While growth in the overall U.S. economy during the 1990's was inflated by rapid growth in the technology sectors and the Internet bubble, Vermont's economy was less affected. Moreover, higher efficiency standards for appliances and extensive Demand-Side Management (DSM) programs by Vermont utilities and, starting in 2000, by Efficiency Vermont, reduced average annual growth rates to about 1.5% during the decade. That growth in electricity sales occurred almost exclusively in the commercial and industrial sectors, in which sales increased about 2.2% annually. Sales to the residential sector, which was especially targeted for energy efficiency programs, showed little growth in electric demand.

Table 3-1 provides a breakdown of total electric consumption in the state for residential, commercial, industrial, and other miscellaneous uses (street lighting, farm), between 1990 and 2003.

GROWTH IN PEAK ELECTRIC DEMAND

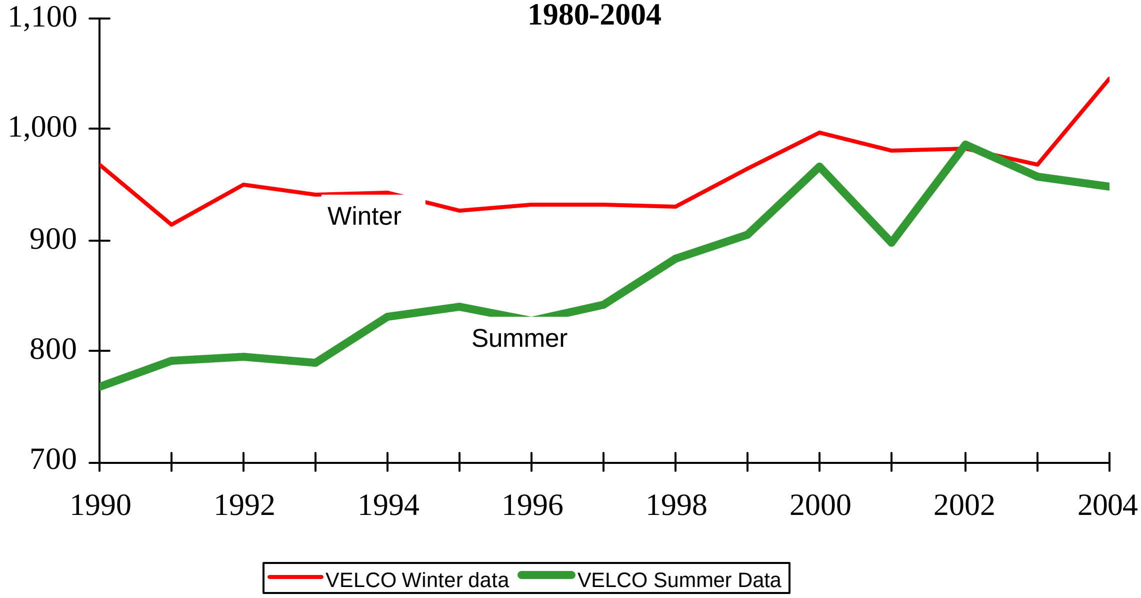
Not only have overall energy sales increased in Vermont, so has peak demand that represents the greatest amounts of electricity required at given times. In Vermont, peak electric demand used to occur in the winter during periods of the coldest weather. With the greater popularity of air conditioners, Vermont's peak electric demand has occurred in the summer months for the last few years. Peak demands also tend to be more erratic than total electrical demand, not only in size but also timing. Peak demand is heavily influenced by Vermont's variable weather, colder winter weather means higher winter peaks, while hotter summer weather means higher summer peaks.

Peak electric demand matters for several reasons. First, Vermont's electric utilities must be prepared to generate or buy enough electricity to meet peak demand. Like other commodities, the cost of buying electricity increases as demand increases. To meet peak demands, utilities must sometimes rely on high-cost generating units because their other supply sources are already at capacity. Second, not only must utilities secure sufficient electric supplies to meet peak demands, they must also be able to distribute them to customers over the network of transmission and distribution lines that cross the state. Therefore, Vermont's poles and wires network must be large enough to handle all of the electricity demanded.[1]

The energy forecasts presented in this Plan are for Vermont as a whole. Their growth rates and other results may not be applicable to individual service territories, specific regions, or localities. The broad groupings of the sectors are residential, commercial, and industrial. The forecasts are based on an econometric model. The key economic and demographic drivers of the base case forecasts are Vermont's anticipated changes in income and population. Business cycles and demographic changes within the population, including age and sex characteristics of the population, are an integral component of the model and the forecast it produces.

[1] The transmission and distribution system can be thought of as an electric garden hose. The size of the hose limits how much water can be provided at any given time.

Figure 3.3 Vermont Electric Utilities: Seasonal Peak Load MWs 1980-2004



Increases in population, income levels, employment, and industrial output are the major influences, but changes in the way electricity is used also affect demand growth. The patterns of future demand in these projections can stand in sharp contrast to the growth experienced in the past. New technologies (such as the development of cost-competitive hydrogen) also affect the new investment and usage decisions by increasing the efficiency of using a particular fuel.

While no model can predict the future with certainty, a base case forecast can serve as a frame of reference for reviewing alternative scenarios to identify a probable range of uncertainty.

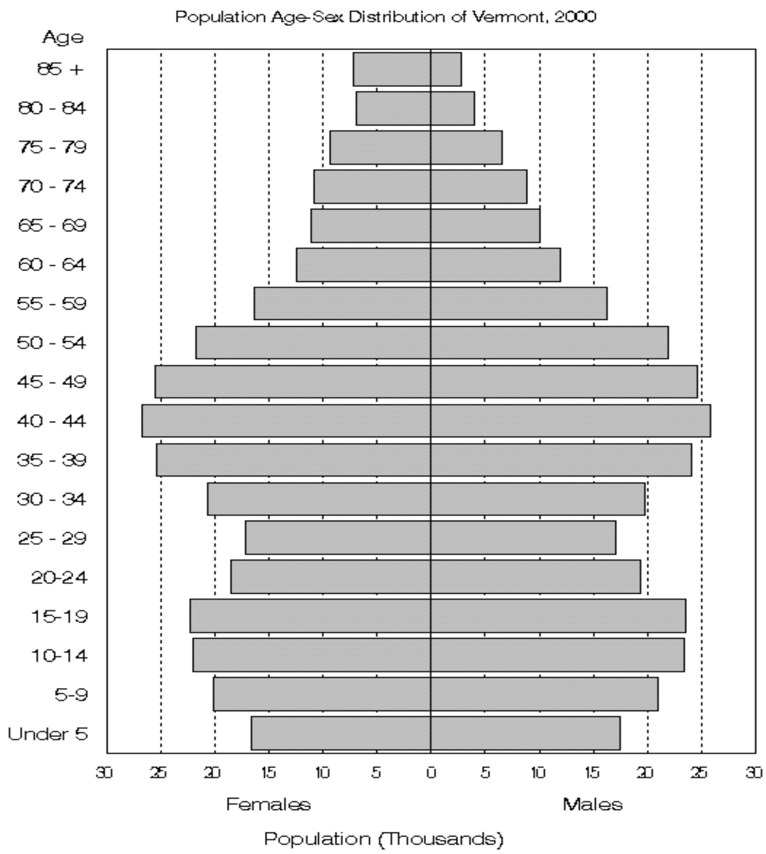
ELECTRIC FORECAST

The forecast of electric demand in Vermont is greatly influenced by demographic and economic trends. During the 1990s, Vermont's population grew at a compound rate of about 0.7% annually. We expect that growth rate to decrease by about half over the 2000-2020 period, to about 0.4% annually.[2] The forecast population change reflects the continued movement of the Baby Boom generation through the population structure. The female boomers that are now ages 40 – 54 have been moving and continue to move out of the 15 – 44 age group, usually regarded as the age group on which fertility is calculated. In the years of the forecast, women ages 15 – 44 will be a smaller proportion of the Vermont population than they are now. The rate of live births (known as the fertility rate) to these Vermont women has dropped from 92 per 1,000 women in 1970 to the current 50 per 1,000 women in 2000. There is no evidence to suggest that this rate will increase during the years of the forecast. The combination of fewer women in the fertile age group and a lower fertility rate has

[2] The economic and demographic forecasts are from a model of the Vermont economy developed by Regional Economic Models, Inc. (REMI)

produced smaller cohorts at the bottom of the pyramid. The under five-year-old segment of Vermont's population has declined 18% between 1990 and 2000.[3]

Figure 3-4 Vermont Population Pyramid



During the years of the forecast, the Baby Boomers will be moving into retirement. The combination of slowing population growth and their retirement will produce a significant drop in the rate of growth of the labor force and a corresponding drop in employment. The labor force, a count of the number of people working or looking for work, in 2000 - 2020 will be growing at 0.7% annually, considerably less than between 1990 and 2000, when annual growth averaged 1.1%. Employment, a count of the number of jobs in the economy, also will be growing at 0.7% annually during 2000 – 2020, less than half of the 1.4% annual rate between 1990 and 2000.[4]

THE VERMONT ECONOMY

The Vermont economy can be represented in several ways: Gross State Product (GSP) is the value of all of the final goods, services, and structures produced by labor and property located in Vermont.[5]

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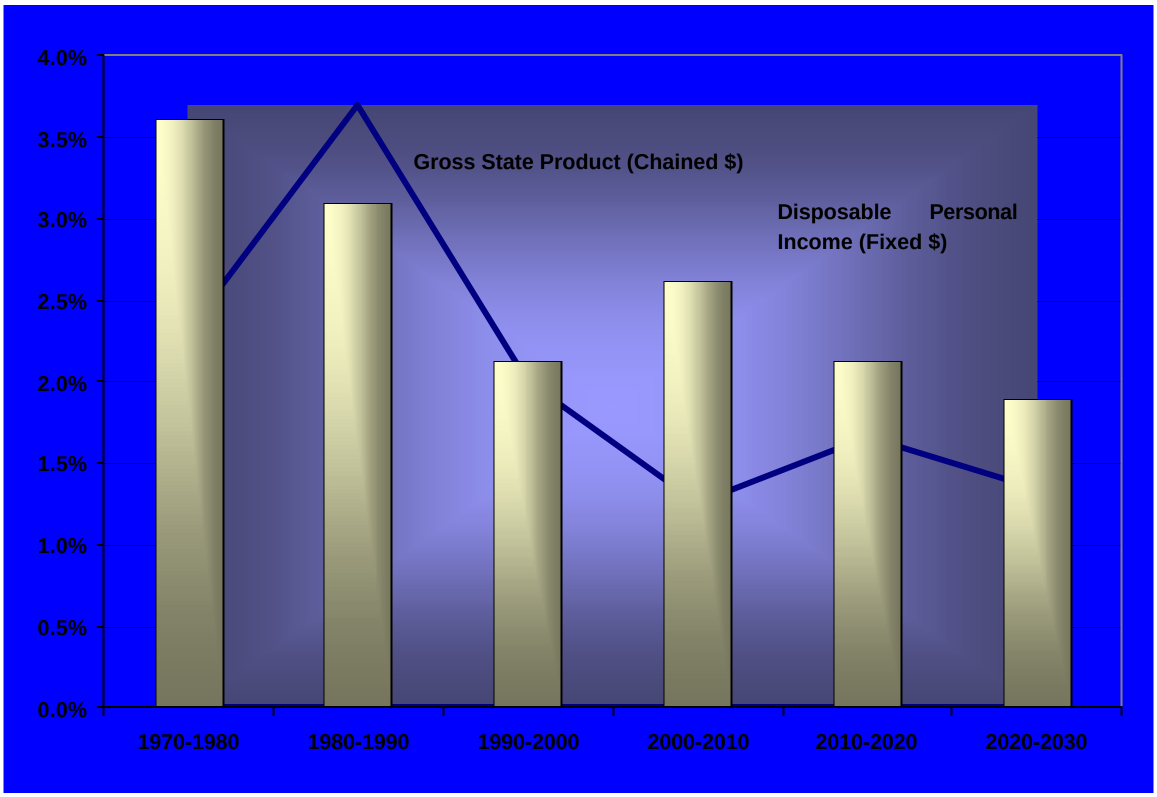
[3] State of Vermont 2000 Vital Statistics, Vermont Department of Health

[4] Usually there are more jobs than people working since a person can have more than one job. The size of the labor force depends on the number of people who could seek work, on employment opportunities and on individual decisions about whether or not to seek work. Since these factors change, the changes in the growth of the labor force and the growth of employment do no necessarily coincide.

[5] The more common term at the national level is Gross Domestic Product (GDP).

Disposable Personal Income (DPI) is the sum of wage and salary disbursements, other labor income, proprietors' income, rental income, personal dividend income, personal interest income, and transfer payments, less personal contributions for social insurance and taxes. These indicators are expressed in 1992 dollars (real dollars) so that the effect of inflation on dollar changes is removed.[6]

Figure 3-5 Vermont Economy Compound Annual Growth Rates



As the rate of growth of population, labor force and employment declines, we will see a declining rate of growth in demand for goods and services and of output of the economy. Whether measured by GSP or DPI, the rate of growth in the Vermont economy is slowing.

Vermont and the nation experienced recessions in 1990 - 1991 and in 2001 - 2002 that severely impacted personal income[7], although the National Bureau of Economic Research declared the 2001 – 2002 recession over. The current economic climate in Vermont is significantly improved and Vermont currently enjoys the lowest unemployment rate in the nation. The forecast accounts for the effects of the recessions of 1990 – 1991 and 2001 – 2002. It does not simulate any further recession, although there is the probability of occurrence given the nature of economic cycles.

In contrast to the economic declines experienced in the recessions of 1990 – 1991 and 2001 – 2002, what we are describing in the economic scenario of this forecast is not an economic recession. The

[6] Chained dollars are real dollars that have been further adjusted to account for the relationship between changing prices and quantities. Gross State Product (GSP) is typically displayed in chained dollars.

[7] *Indicators*. Federal Reserve Bank of Boston, August 2002.

declining growth rate in the Vermont economy in this forecast mirrors that of the U.S. economy and is based mostly on demographic and other long-term changes.

VERMONT'S DEMAND FOR ELECTRICITY

Vermont's demand for electricity will increase modestly over the years of the forecast. Electric demand has increased from 4,961 GWh in 1990 to 5,628 GWh in 2000, a compound annual growth rate of 1.3 between 1990 and 2000. Between 2000 and 2003, the growth rate further dampened to a rate of only 0.3% growth.

The compound annual growth rate in electric demand is forecasted to be about 1% throughout the forecast to 2020.[8] Residential, commercial, and industrial demands are forecasted to be increasing at about the same rates. Within Vermont, demand will vary by region where some regions may see much higher growth rates. On a statewide basis, however, areas showing faster growth are offset by slower growth areas of the state to produce an overall projected growth rate of only 1% throughout the forecast period. A persistent trend of higher growth in the Northwest section of the state is an ongoing challenge for utility managers and regulators (see, Chapter 7's discussion of Current Major Projects.) Conversely, using population growth as a benchmark, the four southern counties of Vermont are not growing except in isolated cases.

Appendix E shows the population densities for Vermont and the areas where population is growing fastest within the state. Changes in population density also reflect patterns of urban expansion. As can be seen in Appendix E, service area growth is occurring fastest in and around Chittenden County and some of the recreational communities in central and southern Vermont. A comparison of population density growth correlates closely with areas that are experiencing the transmission and distribution constraints for which Distributed Utility Planning (DUP) is targeting Area Specific Collaboratives (ASC) (See discussion in Chapter 8.)

While this Plan takes a statewide view, strategies to meet electric demand will vary from one part of the state to another as circumstances warrant. (See, Chapter 8 for Distributed Utility Planning (DUP))

Residential Demand

Vermont's residential consumption of electricity is expected to grow at a slow and predictable rate. After relatively high demand in the 1980s, the 1990s have seen dramatic reductions in residential electric demand due to elimination of most of the electric space heating which, along with other significant demand side management efforts, reduced the rate of growth in residential demand in the 1990s. We expect future growth in residential electric demand to be related mostly to growth in Vermont's population. Electric vehicles and other transportation sources are, as yet, not expected to figure prominently in the demand for electric service.

The forecast models Vermont's future residential electric demand as a function both of its value in the previous year and of the population size. Figure 3-6 shows this forecasted growth in residential electric demand, along with the 95% lower and upper confidence limits. The demand in the residential sector appears to be relatively inelastic (not sensitive to price change, so long as prices remain in a moderate range). This relationship changes when energy prices increase rapidly.

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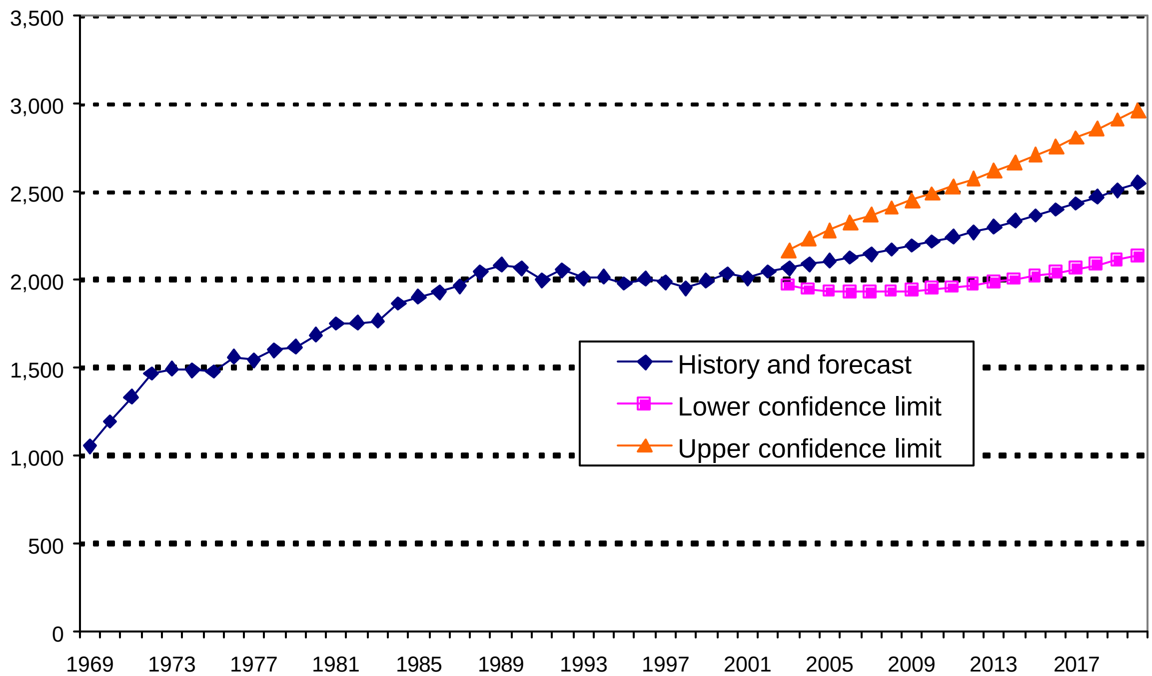
[8] The Department of Public Service (DPS) developed econometric forecasts of electric demand based on the demographic and economic data from REMI.

Figure 3-6 Residential Electric Demand (GWh)

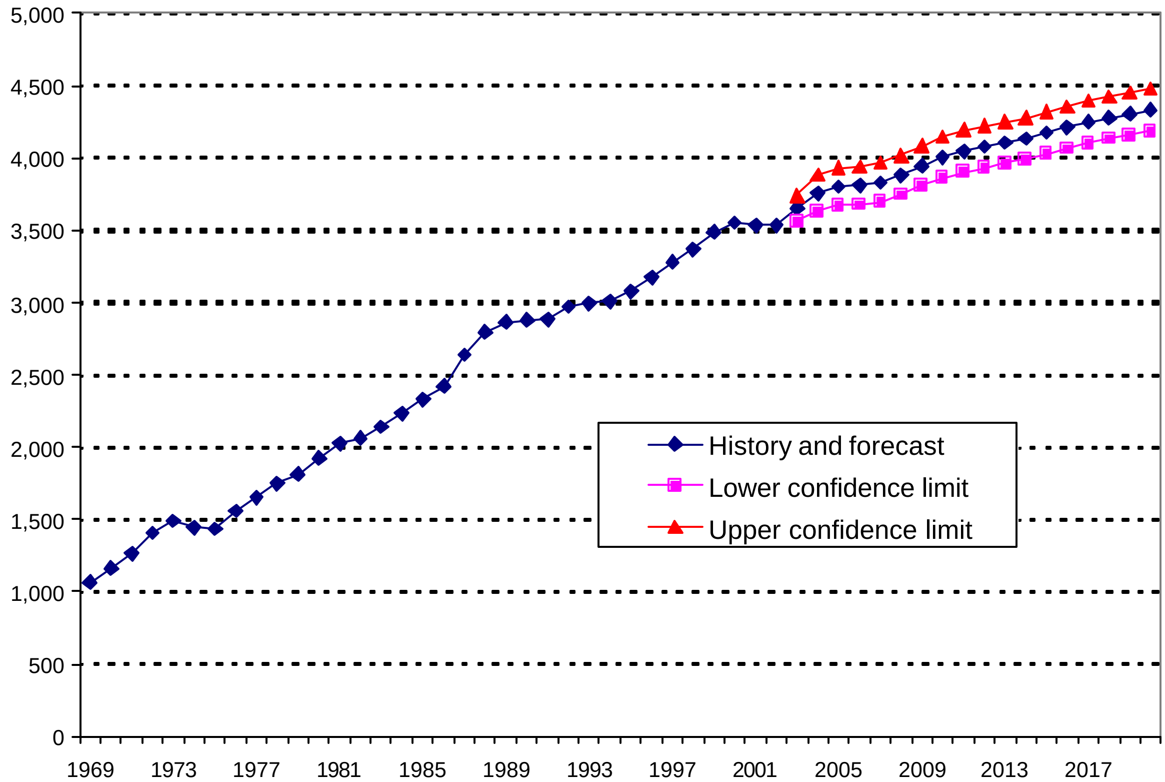


Commercial and Industrial Demand

Commercial and industrial electric demand have been combined for purposes of this forecast. These demands are affected by the state of the economy. Growth was meager or negative during the recessionary periods of the oil crisis of the seventies, the recession of the late eighties and early nineties, and the recession of the late nineties and into the present century. In other years the growth of this sector has been reasonably constant. We believe that the future will see an end to the recession of the last few years and that the growth of electric demand in this sector will continue at a rate similar to past non-recessionary years. We expect future growth in commercial and industrial demand to be related to future employment levels in Vermont.

The forecast understands Vermont's future commercial and industrial electric demand as a function both of its value in the previous two years and of the size of the employed work force. Figure 3-7 shows this forecasted growth in commercial and industrial electric demand along with the 95% lower and upper confidence limits.

Figure 3-7 Commercial and Industrial Electric Demand (GWh)



Total Electric Demand

To have an estimate of Vermont's future need for electricity, it is useful to put together the electric demands of all the sectors. Figure 3-8 shows this composite forecast and 95% lower and upper confidence limits.[9] The Commercial and Industrial demand indicate growth rates different from the Residential. This difference can be explained by variation in economic activity and energy intensity of that activity, such as increasing mechanization and automation.

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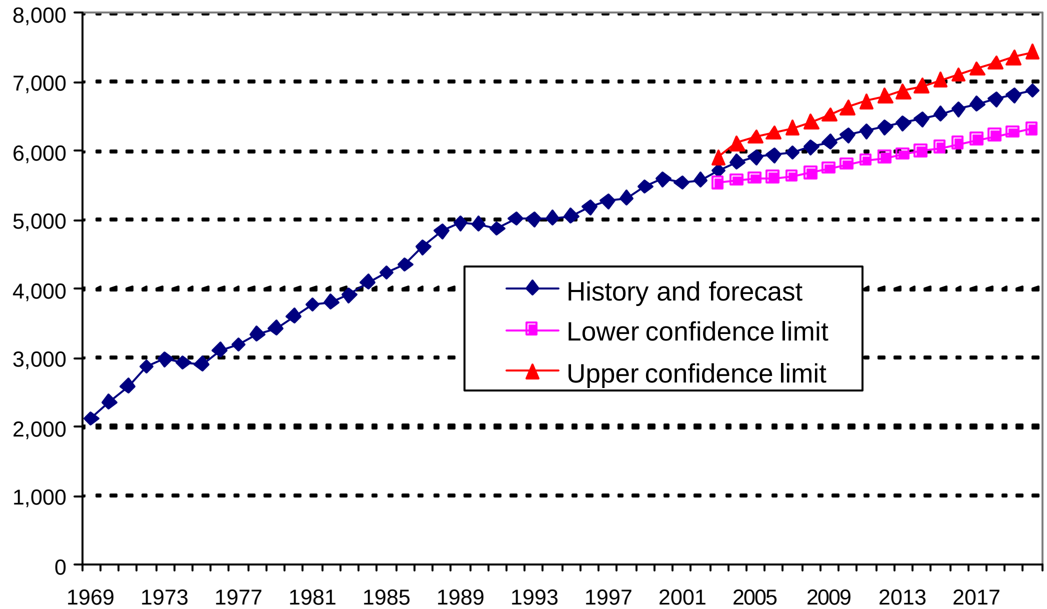
[9] The confidence limits assume that the standard errors in the two equations are independent. This assumption allows us to add the lower and upper confidence limits to produce the confidence limits for this equation. We believe that this is a useful simplification.

Figure 3-8 Total Vermont Electricity Consumed (GWh)



ELECTRIC PRICE FORECAST

Periodically the DPS prepares a long-term forecast of wholesale electric prices in New England. As with any forecast, it relies on data and assumptions that are valid for a particular point in time. To the extent that actual events deviate from those assumptions, the forecast will likely deviate as well. For example, implicit in the forecast is continued moderate growth in annual electric use in the region. Economic conditions have a strong correlation to electric use. A significant change in economic activity in the region will have a corresponding effect on electric demand and prices. Underlying forecast uncertainty associated with projections of fossil fuel prices, particularly natural gas, present one of the greatest challenges in forecasting wholesale electricity prices. There is a considerable degree of uncertainty in the DPS forecast of wholesale electric prices.

METHODOLOGY

The basic premise used to develop the forecast is that in the competitive marketplace, developers will invest in new facilities when the prevailing price rises to a level where they can earn a return on an investment in a new generating station. All other things being equal, as load increases, the laws of supply and demand would say that the price should rise as well. In practice this is not always true because external events like the economy or fuel price changes can have large effects on electric prices. Once new projects are built, supply comes into balance with demand and an equilibrium condition ensues for a while.

In New England, the power plant of choice for developers is a natural gas fired combined cycle plant. Using data from various sources a composite financial picture is developed of a "generic" newly constructed combined cycle plant. Interest rates, required rate-of-return, operations and maintenance costs, equipment performance, and equipment costs are figured into this profile.

The DPS has contracts with Energy Ventures Analysis from Reston, Virginia to develop a price forecast for all fuels delivered to New England. This forecast is broken out by economic sector, including the utility sector. Since natural gas is an especially important fuel for New England electric generation, special emphasis is given to the condition of that industry. The basic assumptions governing the prices of gas into the future revolve around the timing of the introduction into the U.S. market of significant amounts of Liquefied Natural Gas (LNG). Reserves of gas in North America become increasingly difficult to tap, either because they are in deep water or the remaining deposits are small and quickly depleted. The gas industry is unable to keep up with demand on a sustained basis. While there are some reserves in North America that could be developed to supply this increasing demand, it appears that LNG, shipped by tanker from Trinidad/Tobago is the most likely near term source of gas. The forecast assumes that enough of the approximately 40 LNG importation facilities currently proposed for North America will have become operational that supply of gas will return to a balanced condition – although prices will stabilize at a level above that of recent past.

Finally, forward prices are available for one or two years into the future. These come from various marketers in New England and are a reasonable proxy for short term clearing prices.

This data is then combined with a load forecast that predicts when load and supply will be in balance. After that date, it is assumed that the price will be the full cost (fixed and variable) of a combined cycle plant. Table 3-3 shows the results of the most recent DPS forecast prepared in September 2003 and updated in December 2004. The 2001 thru 2004 data points are actual average prices.

Table 3-3

DPS 2004 BASE Market Price Forecast (Prices are in nominal $/MWh)									
2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
40.97	35.77	51.37	52.29	61.63	58.63	54.75	52.50	50.58	51.26
2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
51.74	52.47	53.22	54.01	54.76	55.53	56.58	57.67	58.77	59.91

As part of the forecast, high and low case scenarios were developed. These variations were developed by varying several assumptions on the base case forecast. A high and a low case fuel price forecast was employed and the date at which the full cost of supply (variable and fixed costs) was reflected in the market price was varied. The results of those cases are presented in Figure 3-9 and Table 3-4.

Figure 3-9

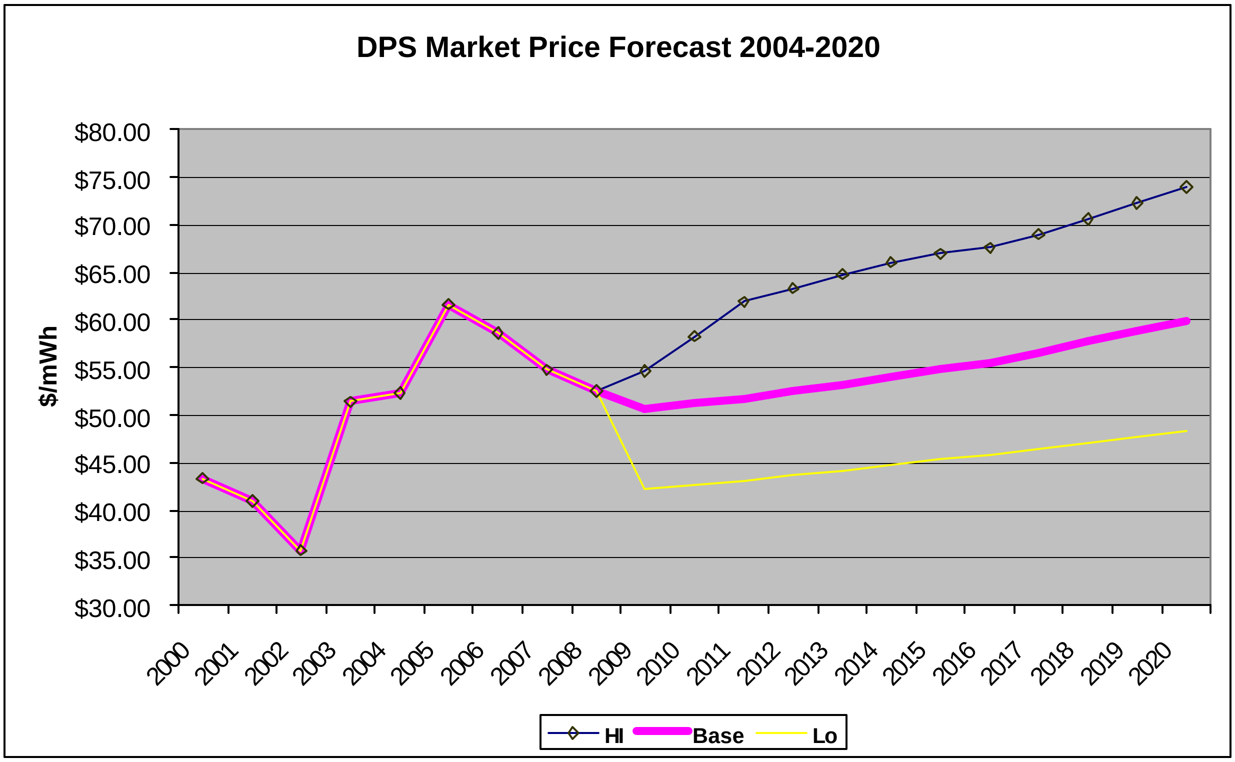


Table 3-4

DPS 2003 HIGH Market Price Forecast (Prices are in nominal $/MWh)									
2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
40.97	35.77	51.39	52.29	61.63	58.63	54.75	52.50	54.61	58.23
2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
61.58	63.28	64.76	66.03	66.92	67.55	68.95	70.52	72.23	73.96

CHAPTER 4: Existing Supply Resources and Policy Issues

INTRODUCTION

This chapter deals with the major electric energy resources that Vermont currently uses. The Vermont supply mix is currently characterized by a stable long-term mix with commitments focused around two sources. Vermont utilities have fixed commitments from Hydro Québec (HQ) and Vermont Yankee (VY) that supply about two thirds of the energy used in the state. As discussed below and in Chapter 1, this means a significant portion of Vermont's supply portfolio is concentrated in only two resources. This fact poses a major challenge to utility managers and policymakers over the planning horizon. The sale of VY has eliminated the risk of decommissioning costs for the ratepayers of Vermont, but a significant market exposure remains, should the plant be retired prematurely or be taken out of service for an extended period. HQ, as a system resource not tied to any particular generation source, was thought to be a more reliable resource. The ice storm of 1998, as well as the cold snap in January 2004 have shown that a reliable transmission network connection between HQ and Vermont is integral to the relationship. A likely scenario is that the current committed resource mix will remain constant through 2012 when the contract with VY expires.

Well over three quarters of Vermont's energy supply is not directly tied to fossil fuel prices. Vermont is a member of New England Power Pool (NEPOOL) and as such participates in the power market administered by the Independent System Operator of New England (ISO-NE). As a result, Vermont cannot completely escape the effects of fossil fuel price volatility, but the combination of fixed price contracts and unit ownership currently in effect greatly mitigates the cost impacts of fluctuating commodity fuel prices.

The discussions in this plan focus on the aggregate interests of all of the Vermont utilities and the obligation to serve the entire load of the State of Vermont. While this reference is useful in examining the big picture regarding Vermont power supply commitments, each utility is responsible for its own portfolio of resources and for serving its own load. As a result, individual utilities may have resource portfolios that are significantly different from the aggregate resources discussed below.

UTILITY-OWNED ELECTRIC GENERATING FACILITIES IN VERMONT

Ownership of generation by utilities can function as a hedge against the volatility of market prices. The current mix of utility-owned facilities in Vermont also contains many examples of generation with environmental impacts that are low, compared to the alternatives. Utility-owned electric generation in Vermont includes examples of hydroelectric power, wind power, and biomass-fueled generation. Fossil fuel generation also makes important contributions to the power currently supplied by Vermont utilities as peaking units tied to reliability.

HYDROELECTRIC RESOURCES

Vermont utilities own 84 MegaWatts (MW) of hydroelectric facilities. Of this total, 51 MW operate on a run-of-river basis, generating electricity from the water as it flows into the facility. The remaining capacity is able to store, or pond, water behind their dams for use in generating during peak load periods. The ability to pond water makes this second group of hydro facilities more valuable economically, since it can shift production of energy from times when less costly alternatives are available to times when alternatives are more expensive.

Hydropower does not degrade air quality and it is a renewable source of power. Dams, alter natural stream flows and change the natural environment in ways that can negatively impact aquatic life like the reproduction of fish that rely on migration upstream to spawn can be interrupted. Hydro facilities are typically long lived, but many require periodic renewal of their federal operating licenses. Currently several of Vermont's utility owned hydro facilities are seeking relicensing and many others will need to do so before the end of the decade. Concerns surrounding the environmental impacts of these facilities frequently lead to operating restrictions being imposed as conditions for relicensing. These restrictions will most likely reduce output and in some cases may shift operations from ponding to run of river.

Hydropower is also a type of generation supplied to Vermont through in-state Independent Power Producers (IPPs) and through contracts with major out-of-state hydropower producers. These supply sources are discussed further below.

WIND RESOURCES

Vermont began prospecting for wind turbine sites in the late 1970s. Green Mountain Power (GMP) pioneered the development of wind energy for Vermont utilities with their project in Searsburg. Knowing that higher elevations have better wind, but are more environmentally sensitive, the challenge from the start was to find a windy site that would be environmentally acceptable and still be economically feasible. Even with that goal in mind, the Searsburg site can be characterized as a demonstration project. Upon completion in 1997, the 6 MW Searsburg project became the largest wind power facility in the eastern part of the United States. It has served as a demonstration project, proving that the harsh winter climate in Vermont can successfully host a wind facility. The project received support from the U.S. Department of Energy (DOE) and the Electric Power Research Institute (EPRI) for participation in their Utility Wind Turbine Verification Program. As such, many of the lessons learned about cold weather operation of wind turbines at Searsburg have been directly incorporated into the present generation of wind turbine technology.

Figure 4-1 represents the historical monthly average energy production from the Searsburg plant and the graph shows the plant produces more energy in the winter months and less in the summer. Production during the winter months seems to be fairly constant. The average annual production of 12,592 Mega Watt hours (MWh) results in a 24% capacity factor.

Figure 4-1

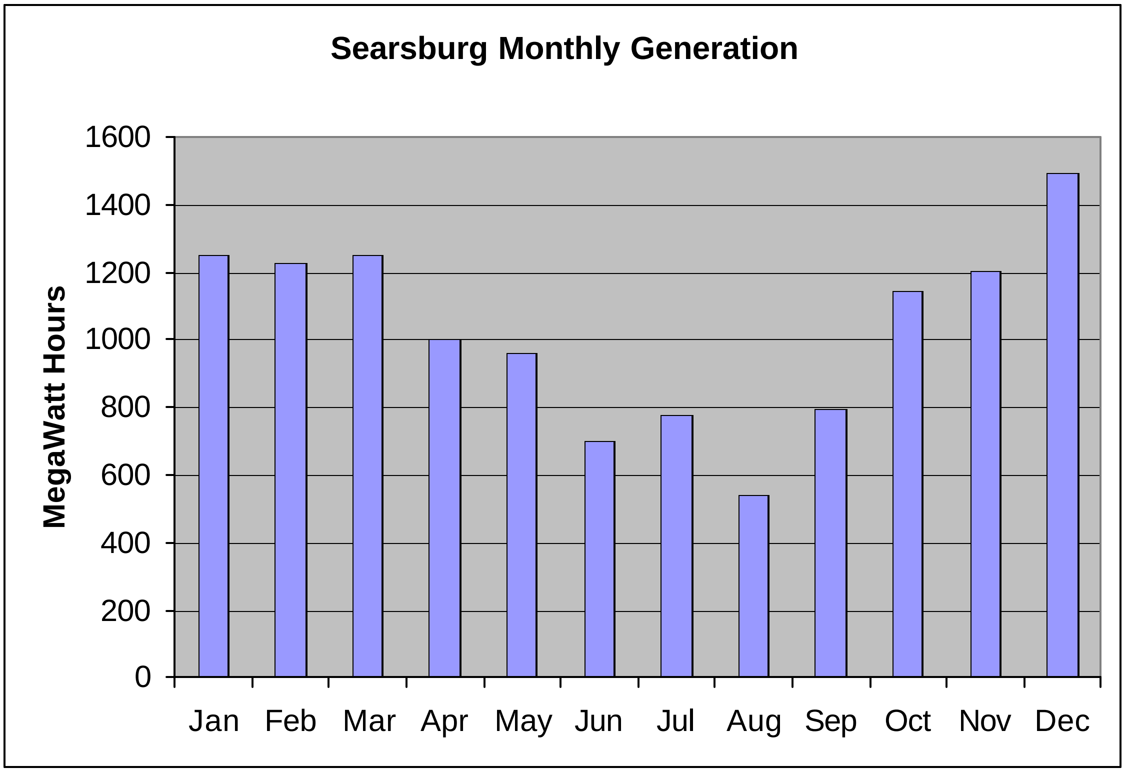


Table 4-1 Searsburg Monthly Generation

Month	Average Production (MWhs)
Jan	1252.326
Feb	1224.902
Mar	1248.683
Apr	1004.147
May	963.450
Jun	702.827
Jul	776.118
Aug	539.457
Sep	793.629
Oct	1145.876
Nov	1206.110
Dec	1493.197
Annual	12592.240

BIOMASS RESOURCES

Wood

The 53 MW McNeil Station, the largest wood-fired generator in the world when it came on-line, was developed with great promise as an instate generator, a market for low-grade wood to aid Vermont forest management, insulation from volatile oil prices, and a significant employer generating other associated economic benefits. As a laboratory to evaluate biomass generation in Vermont, McNeil was expected to justify building more wood fired stations.

Eventually, only part of the promise was realized. After the plant opened in June 1984, McNeil's fuel price of about 3.5 cents/kWh was not competitive during the ensuing period of low oil prices beginning in 1986. In 1985, fuel management problems on site and at the remote wood depot in Swanton, contributed to a negative perception of McNeil. Fuel management problems have now largely been resolved. Burlington Electric Department (BED), the plant's principal owner, has taken corrective measures to control fuel inventory by utilizing short-term contracts that provide the flexibility to buy wood to meet fluctuating needs. BED has also worked with the forestry community and its fuel suppliers to develop wood harvesting guidelines that ensure that the forests remain a sustainable source of energy for Vermont. The plant is the site of state-of-the-art work being carried out in wood gasification. Development of this technology could drastically improve the efficiency of combustion and significantly decrease the resulting emissions. The smaller scale of the applications envisioned could greatly expand the possibilities for biomass electric generation in the world.

In 1989 McNeil added the capability to fire its boiler using natural gas, either together with wood, or as an alternate fuel. This was intended to allow the plant an opportunity to be used when wood firing is not economic. In practice, this was seldom the case, and gas has not been competitive with wood for over three years. The dispatch pricing and fuel scheduling have been reviewed in light of the new fuel capability with the intention of achieving greater plant operation consistent with maintaining McNeil's status as a wood burning plant. As the rest of New England moves to a gas-based electric supply system, the ability of the McNeil plant to compete with other gas-only combined cycle plants may be limited.

The plant has proved invaluable in mitigating effects from several recent events that threatened the reliability in the Burlington area. In January 1998, an ice storm ravaged the northwestern part of the state, downing power lines and restricting transmission access to the Burlington area. In March 2000, the Phase Angle Regulator (PAR), which controls power flow over the PV20 transmission line from Plattsburg, New York to Vermont, failed. This meant that power flow over the line was limited, and again the reliability of supply in the northwestern part of Vermont was threatened. In each case, the McNeil plant was able to provide support to the region and greatly ease the problems associated with these outages of key components of the transmission system.

Current conditions still do not allow McNeil to operate as a baseload facility as originally envisioned. When the plant was built, it was envisioned to operate at a 70% capacity factor, however, it is presently operating at a 50% - 60% capacity factor. During an era of low oil and gas prices, McNeil operated at a low capacity factor of about 20%, a period in which the economic nature of the project was in question. At a minimum, McNeil gives its owners a price ceiling on the market prices they face. Changing fuel prices, energy markets, and environmental factors, may register increased benefits from McNeil in the long run.

In late 1992, the 20 MW Ryegate wood fired generation plant came on-line. This is the second largest wood-fired facility in Vermont and the only IPP selling through the Vermont purchasing agent that is not a hydroelectric facility. Provisions in Ryegate's 20-year contract allow it to produce and sell energy at will; not subject to economic dispatch or bidding into the market.

If wood is to take on a more important role as a fuel for generating electric energy in Vermont, then the Department of Public Service (DPS), the utilities, the forestry community, and the fuel wood suppliers must continue to develop and follow wood harvesting practices that ensure forest resources are being consumed at a rate of use at or below the natural regeneration rate, and in a manner that is consistent with efforts to protect the environment over time. In this way the health of the forests is maintained (including trees, soils, and habitats) while yielding a consistent supply of fuel for energy production. Further, the DPS will work with the Agency of Natural Resources (ANR) to ensure that air quality considerations are taken into account. Finally, new technologies for using wood more efficiently and more economically must be developed, allowing this fuel to become a larger part of the Vermont resource mix.

Landfill Methane

As refuse breaks down in landfills, it emits large amounts of gas that eventually escape into the atmosphere. Much of this gas is methane, the key component of natural gas. Federal law requires large landfills to control their methane emissions. To do this, operators must burn off the gas by collecting it in pipelines buried in the landfill. Rather than flaring the gas at the landfill, entrepreneurs have developed ways to use landfill methane to power small generators, converting what was formerly wasted energy into valuable electricity.

At present Vermont has two landfill methane generating systems operating at the Brattleboro and Burlington landfills. The Brattleboro site currently produces 1 MW and Burlington 0.6 MW. The Washington Electric Cooperative (WEC) is building a 3.5 MW facility at the landfill in Coventry, Vermont. In addition, several smaller independent projects are proposed for smaller landfills around the state. Since production of gas at landfill sites tends to peak several years after closure and then decline, these generation facilities are not expected to have productive lives that are as long as conventional generating plants. Recognizing this fact, the developers have structured the facilities as modular units. As landfill gas emissions increase, additional units are added to reflect the increased capacity of the landfill. As the emissions decline, units are removed and can be re-sited.

Refuse

Vermont currently receives no electricity from the direct combustion of refuse. When Central Vermont Public Service (CVPS) sold its service territory in New Hampshire, its contract to purchase power from the 4 MW New Hampshire-Vermont Solid Waste facility in Claremont, New Hampshire was sold with the territory. Vermont's only other refuse fired facility, the VICON plant in Rutland has been shut down since 1988. The bankrupt facility had been purchased by Vermont Integrated Waste Solutions (VIWS). The new owners had hoped to return the plant to operation, but failed to obtain the required air quality permit, so the plant was dismantled.

FOSSIL-FUEL RESOURCES

Vermont utilities own an ample supply of fossil fuel fired peaking capacity—the generation that is used when electric usage levels are highest. In particular, BED and GMP appear to have significant peaking capacity available through such units as the Burlington and Berlin gas turbines. Many of the other Vermont utilities also own diesel or combustion turbines, which, though smaller than the Berlin and Burlington units, provide adequate and economical peaking and reserve capacity. Should the market supply diminish, Vermont utilities will have to determine whether future peaking capacity entitlements will be met by physical assets located within Vermont, long or short term contracts, or to purchase insurance against peak exposure through some type of financial instrument available from marketers in New England.

Vermont utilities own entitlements in a number of intermediate load units, both in and out-of-state. Out-of-state examples include the Yarmouth (Wyman) 4 unit, which burns oil; and the Stony Brook station combined-cycle units in Ludlow, Massachusetts, which burn both natural gas and oil. Vermont Marble has an 8 MW cogeneration plant at its industrial facilities in Florence, Vermont. This distillate oil-fired plant produces electricity and uses the waste heat from the generation process to dry its powdered marble product. High fuel costs and the availability of relatively less expensive base load power in NEPOOL have kept the Florence cogeneration plant from operating as a base load source as originally anticipated.

In the past, many new generation sources in the region have been natural gas fired. In Vermont, natural gas is currently available only in the northwestern part of the state. While there have been proposals for gas-fired cogeneration units adjacent to industrial sites from Sheldon to Williston and even down to Rutland and Bennington, none have been built. (As is discussed in Chapter 5, UVM is evaluating a possible co-generation plan.) The lack of financing for independent merchant generation, caused in part by the current excess capacity situation, makes similar proposals unlikely in the near future. Extending the availability of natural gas to other industrial centers of Vermont would improve opportunities for cost-effective generation or cogeneration. It appears that IPPs are most likely to pursue these opportunities, as regulated companies appear reluctant to accept the risk of such capital-intensive investments.

The prices of oil and gas generation vary along with the prices of the fuel inputs. Although the state does not have a direct dependence on oil or gas resources, the predominance of gas generation in New England means that gas is the fuel setting the marginal price for many hours of the year. Elevated gas prices mean elevated market prices. Volatile gas prices mean volatile market prices. Taken as a whole, Vermont's overall reliance on oil and gas generation is small compared with the rest of New England, although individual utilities are serving significant parts of their loads with market-based purchases. Even with a moderate increase in short and medium term market purchases, the state's exposure to risk from fossil-fuel price volatility is likely to remain limited.

UTILITY-OWNED NUCLEAR

Vermont's electric energy source mix includes 273 MW from nuclear power. Vermont utilities, that formerly owned the VY nuclear power plant, now have a 55% contract-based share of the plant’s power output. Vermont utilities still own smaller allotments in the Millstone 3 plant in Connecticut, which continues to operate the Yankee Rowe, Connecticut Yankee, and Maine Yankee plants, which have been permanently shut down (but for which Vermont utilities still incur costs).

VERMONT YANKEE (VY)

Vermont Yankee is Vermont's single largest supply source. Entergy purchased the plant from its Vermont owners in 2002. The plant is a nominal 540 MW capacity Boiling Water Reactor (BWR) and is located in Vernon, near Brattleboro. The plant began generating commercially in 1972 and is licensed to operate until 2012. It is one of five operating nuclear plants in New England and also one of five nuclear plants in Entergy's northeast fleet.[1] Through 2003, VY has generated an annual average of over 3.4 billion kWh, achieving a cumulative output approaching 80% of its maximum potential. Recently, the plant has been achieving very high levels of output. In 2003, a year without a refueling outage, it operated at a capacity factor of 99.5%. In 2001 and 2002 (years with refueling outages) it operated at an average capacity factor of 91%. In 2003, VY supplied almost 35% of Vermont's energy requirements and almost 28% of the peak capacity requirements. When the plant is unavailable, a large block of Vermont's load must be served by alternative sources.

SALE OF VERMONT YANKEE (VY)

Prior to 2002, VY was owned by Vermont Yankee Nuclear Power Corporation (VYNPC), a single asset entity owned in turn by eight New England utilities. Vermont utilities owned 55% of VYNPC. In 2002, the plant was sold to Entergy Nuclear Vermont Yankee, LLC, a subsidiary of Entergy Corporation of New Orleans, Louisiana. Entergy is the second largest nuclear generator in the U.S. owning ten nuclear plants, five in the South and five in the Northeast. Entergy brings to VY significantly greater resources and nuclear expertise than its former owners.

While the sale to Entergy did not change the amount of capacity and energy available to Vermont utilities, it allowed those utilities to renegotiate the price. Under the sale agreement, GMP and CVPS purchase energy from the plant at a cost of between 3.9 and 4.5 cents/kWh through March 2012, the end of its current operating license. These prices are significantly lower than the prior commitments, which ranged from 3.9 to 5.5 cents/kWh. Furthermore, should prices in the New England spot market decline below projected levels, the price paid by GMP and CVPS will decline proportionately.[2] And, under the agreement, those utilities are protected from higher than expected market prices. The transaction also provides Vermont utilities the additional benefit of shedding the risks of premature failure of the plant and the cost uncertainties of decommissioning the plant. The only risk the utilities remain subject to is from interruptions in the plant's operation, since the contract provides energy to GMP and CVPS only if the plant actually operates.[3] Should that happen, GMP and CVPS would need to find other supplies.[4] However, in the next few years, if an interruption is found to have been caused by the power up-rate (described below), Entergy will reimburse the utilities for certain net losses incurred because of the interruption in power from VY.

UPRATE OF GENERATING CAPACITY

In 2003, Entergy petitioned the Public Service Board (PSB) for an increase in generation, known as a power up-rate, at the plant by about 20%, from 510 MW to 620 MW. In March 2004, the PSB conditionally granted that request, subject to an independent engineering assessment of the plant. During its Spring 2004 refueling outage, Entergy implemented physical modifications to the plant for power up-rate, including a new high-pressure turbine, new feed water heaters, a refurbished main generator, and other modifications. A decision by the Nuclear Regulatory Commission (NRC)

[1] The other New England plants are Millstone 2 and 3 (Connecticut), Pilgrim (Massachusetts), and Seabrook (New Hampshire). The other plants in Entergy's northeast fleet are Pilgrim (Massachusetts), Indian Point Units 2 & 3 (New York) and James A. Fitzpatrick Nuclear Plant (New York).

[2] If the market price for electricity falls below those prices for a year, a change would be made the following year. Instead of paying the agreed-upon price, Vermont utilities would pay 105% of the previous year's market price. The low-market adjuster does not kick in until November 2005.

[3] This is known as a unit-contingent contract. The HQ contracts, by contrast, are not tied to any specific generating units, and are know as system energy contracts.

[4] In July 2004, a ten-day outage at VY caused by a fire in the transformer cost Vermont utilities about one million dollars.

regarding the power up-rate is expected in 2005. Approval would allow the plant to increase power by approximately 70 MW at that time. Power would be increased an additional 40 MW following its Fall 2005 refueling outage.

The DPS was specifically concerned about plant reliability following power up-rate as other up-rated plants in the U.S. have had reliability problems following up-rate modifications. It negotiated a ratepayer protection plan as part of the settlement with Entergy in late 2003 to compensate Vermont utilities for costs associated with outages and power reductions caused by power up-rate. This protection plan will be in effect until the Spring 2007 refueling outage.

As part of the proceeding before the PSB, Entergy agreed to a revenue sharing provision related to its sales of up-rate power, and as such the DPS agreed that the power up-rate proposal was an economic benefit to Vermont. However, the DPS continued its review of nuclear safety aspects. At the time of this Report, the DPS continues to have questions regarding the safety aspects of power up-rate and is pursuing answers to these questions through the Atomic Safety and Licensing Board (ASLB) and the Advisory Committee on Reactor Safeguards (ACRS) processes at the NRC.

ON-SITE NUCLEAR WASTE STORAGE

An issue with nuclear energy is the disposal of radioactive waste stemming from plant operation and decommissioning. High-level radioactive waste consists of spent nuclear fuel; disposal of this waste is the responsibility of the federal government. Low-level radioactive waste consists of radioactive products and contaminated material other than spent fuel; disposal of this waste is the responsibility of the individual states.

For high-level radioactive waste, the Federal Nuclear Waste Policy Act of 1982, as amended, directs the U.S. Department of Energy (DOE) to site, design, construct, and operate the nation's first geologic repository to dispose permanently of spent nuclear fuel. The DOE established contracts with nuclear utilities in 1983 to collect one mill (0.1 cent) per each kWh of nuclear energy generated, and in return to begin removing spent fuel from reactor sites starting in January 1998. The so-called “mill charge” has been collected and is passed through to ratepayers. As of Fall 2003, ratepayers across the U.S. had contributed $12.5 billion to the Nuclear Waste Fund, which with interest results in an overall $19.8 billion collection from ratepayers. However, the DOE did not begin removing spent fuel from nuclear sites in January 1998, and is therefore in breach of their contract. Settlement lawsuits by all nuclear utilities are ongoing.

The federal government has made significant progress toward its responsibility to dispose of high-level radioactive waste. In July 2002, the Congress approved the President’s recommendation, and overrode Nevada’s veto of the Yucca Mountain site for development as a repository for the disposal of spent nuclear fuel. Now the DOE must complete a challenging licensing process with the NRC for Yucca Mountain. Many people doubt that they will meet the currently projected completion date of 2010. While currently there is recognition in both the DOE and the Congress that disposal of spent nuclear fuel is a national problem that must be solved, Yucca Mountain opponents are likely to use legal and legislative means to attempt to stop the project.

VY has expanded its on-site fuel storage three times, most recently in 2000. The plant will use up its existing capacity and need additional capacity for spent fuel storage for its Spring 2007 refueling outage if the uprate is granted. They must still reserve enough storage to hold all the fuel assemblies currently in the reactor in addition to whatever spent fuel it is holding. It is expected that Entergy will seek approval in early 2005 to implement dry cask storage, a method by which spent fuel is stored in shielded, passive storage containers. Dry cask storage is in use at approximately half of the U.S. nuclear plants.

General federal approval of the dry cask storage system Entergy plans to use has been obtained for sites such as VY. State approval must be obtained in accordance with 10 V.S.A. Chapter 157, which requires that the general assembly find that the storage promotes the general good of the state. Following approval from the legislature, Entergy will also need approval for any dry cask facility from the PSB under 30 V.S.A. § 248.

To dispose of low-level radioactive waste, VY currently uses two facilities: Envirocare of Utah and Barnwell, South Carolina. Envirocare accepts Class A waste, the lowest category of low-level radioactive waste, which comprises approximately half of VY's operational waste and 90% of projected decommissioning waste. Barnwell currently accepts all categories of low-level radioactive waste, and VY sends Class B and C waste to Barnwell. South Carolina has announced that after 2008, Barnwell will no longer be available to nuclear plants outside the Atlantic Compact, including VY.

Vermont is a member of the Texas-Maine-Vermont Low-level Radioactive Waste Disposal Compact (the Texas Compact)[5], in which Texas is obligated to develop a disposal facility within its state. Prior to 2003, siting in Texas was stalled due to legislative restrictions. In 2003, the Texas legislature enacted legislation to establish a siting process there, and in July 2004, Waste Control Specialists, a private developer, submitted an application to construct a compact facility in Andrews County, Texas. This process provides for the issuance of a license by the end of 2007. Even if action in Texas is delayed, VY will continue to have options available. In contrast to storage for high-level radioactive waste, they have sufficient onsite storage capability to meet its low-level radioactive waste needs well into the future.

POTENTIAL FOR LICENSE EXTENSION BEYOND 2012

Starting in 1998, the NRC began granting 20-year operating license renewals to nuclear plants. Currently, approximately one-fourth of U.S. nuclear plants have received license renewals, and it is expected that almost all existing nuclear plants will renew their operating licenses. While Entergy has not announced its intentions regarding VY license renewal, Entergy would need to submit its license renewal application in 2007 to renew its operating license that expires in 2012. It is expected that the decision to pursue this license renewal would depend on a combination of production and market cost factors. As part of its purchase of VY, Entergy committed not to operate beyond March 21, 2012, without seeking approval from the PSB. Entergy's current Certificate of Public Good (CPG) to own and operate VY expires on March 21, 2012.

DECOMMISSIONING ISSUES

The cost to decommission VY following permanent closure of the plant, and to return the site to its original condition, was identified as an issue in previous Electric Plans. Under previous ownership, decommissioning costs were passed through to ratepayers. Projections of these decommissioning costs increased dramatically over the 1980s and 1990s.

One of the benefits of the sale of VY to Entergy was the removal of the decommissioning liability from the ratepayers. As part of the sale, Entergy received the VY decommissioning trust fund valued

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[5] The state of Maine withdrew from the Texas Compact in April 2002 and its withdrawal became effective in April 2004.

at $310.7 million.[6] In return, Entergy assumed the responsibility for decommissioning, including the risks of increasing decommissioning costs, without recourse to additional ratepayer payments. In the sale transaction, Entergy outlined a contingency plan that would be pursued should sufficient funds for decommissioning not be available at the time of shutdown. The plan provided for Entergy to place VY in a safe storage mode to allow the decommissioning fund to grow through investment returns to a level sufficient for decommissioning.

Vermont continues to have an interest in the adequacy of the decommissioning fund because of the state interest in the ultimate removal of radioactivity from the VY site and its return to its original condition. Therefore, the PSB ordered the following provisions in the sale transaction to Entergy:

- Entergy shall notify the PSB and the DPS every six months as to the status of Entergy financial guarantees for VY;
- Entergy shall report to the PSB and the DPS the status of decommissioning funds and the latest NRC calculation at such times as it is reported to the NRC. Entergy shall make this information available to the public;
- Entergy shall update its site-specific decommissioning study every five years and submit the results to the PSB and the DPS. Entergy shall inform the public of the estimated cost of decommissioning which resulted from the study; and
- Entergy shall file with the PSB and the DPS a copy of the Post Shutdown Decommissioning Activities Report (PSDAR), and shall update it annually.

SINGLE SOURCE RELIANCE ON VERMONT YANKEE (VY)

Previous editions of this Plan pointed out that utilities should consider ways to reduce the risk associated with Vermont's reliance on VY as a single source. The sale of the plant to Entergy alleviates much of the exposure associated with ownership of it. Should the plant become unavailable for any reason, Vermont would remain exposed to the market to replace that energy which would have come from VY. Since the plant is no longer owned by the Vermont utilities, they are not liable for any continuing payments to VY should it become unavailable. Nonetheless, this exposure to market prices is significant and Vermont owners of VY entitlements should consider further diversification through “swaps” or other instruments that can spread the risk of the State’s heavy reliance on VY for price stability.

QUALIFYING FACILITIES (QF)

Independent Power Producers (IPPs) are producers of electrical energy that are not owned by public utilities, but make electric energy available for sale to utilities or to the market. They may be privately held facilities, cooperatives such as rural solar or wind energy producers, or non-energy industrial concerns capable of feeding excess energy into the system. IPPs can be of any size or fuel type. Federal law guarantees a market to those who meet certain qualifications. Such Qualifying Facilities (QF) must produce electricity using a renewable resource or be cogenerators. QFs are also limited to a maximum size of 80 MW. Federal law allows utilities to invest in up to 50% of a QF.

[6] Decommissioning is estimated to cost $621 million in 2001 dollars.

In 1983, the PSB adopted Rule 4.100 in response to a mandate contained in the Public Utilities Regulatory Act (PURPA), enacted by the U.S. Congress in 1978. PURPA required retail utilities to purchase power generated by QF's at the utilities' avoided costs.[7] States were required to adopt rules to implement this act.

Unlike the QF systems adopted by other states, PSB Rule 4.100 established one statewide, unified system for purchasing and allocating QF-produced power. Under this system, the DPS calculated a set of statewide avoided cost rates to be paid to QF's. In addition, the Rule established a purchasing agent to act as broker between the QF's and the Vermont distribution utilities. The purchasing agent also ensured that the selling facilities complied with their various operating and contractual conditions in their contracts.

In Vermont, PURPA has resulted in a broad range of QF projects. Some of these represent local entrepreneurs renewing an old dam or utilizing low-grade wood as a fuel. Projects are powered by water, wood, gas extracted from landfills, and cow manure. Some developers are out-of-state venture capitalists. The Ryegate project includes a utility, CVPS, as a minority investor, and the Huntington Falls hydro project has been developed completely by Vermont Marble.[1]

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[7] Definition under PURPA: Costs
Section 210 of the PURPA required that electric utilities purchase energy from qualifying IPPs (or QF's) at the utilities' avoided costs (what the utilities would have to pay, on average, for energy from other sources). In order to assist IPP developers in financing their projects, many states, including Vermont, offered IPP's long-term contracts. These were fixed price contracts determined by cost projections made in the late 70's, at a time when oil prices were expected to remain at elevated levels indefinitely. As a result, contracts for QF power tend to be very high-priced. Recent efforts at renegotiation have resulted in some reduction in cost of IPP power and as current IPP contracts expire the trend of IPP power cost is toward market price. There have been several new projects that have requested avoided cost rates. These contracts have been short term and indexed to the regional market price.

[1] Vermont Marble was able to hold a 100% ownership in the Huntington Falls facility under a provision in the law that waives the 50% limitation for companies whose utility business represents only a minor part of their overall business.

Table 4-2

Independent Power Projects Selling to Vermont Power Exchange				
Project	**NEPOOL Capacity (MW)**	**Fuel**	**Est. AnnualOutput (GWh)**	
Comtu Falls	0.46	Water	2.37	
Dewey's Mills	2.79	Water	7.08	
Emerson Falls	0.23	Water	0.51	
Martinsville Hydro	0.19	Water	0.62	
Woodside Hydro	0.12	Water	0.57	
Slack Dam	0.37	Water	1.78	
Killington Hydro	***	Water	0.26	
Barnet Hydro	0.3	Water	2.11	
Brockways Mills	**	Water	**	
Dodge Falls Dam	5	Water	20	
Ottauquechee Woolen Mill	2.18	Water	5.03	
Kingsbury Hydro	0.2	Water	0.73	
Ladd's Mill	0.14	Water	0.31	
Moretown Hydro	0.58	Water	3.4	
Nantana Mill	0.11	Water	0.52	
Newbury Hydro	0.27	Water	1.21	
Winooksi 8	0.91	Water	3.53	
Sheldon Springs	26.38	Water	65.85	
Huntington Falls	5.76	Water	22	
Winooski 1	7.1	Water	23.3	
Total Hydro	53.39		156.44	
Ryegate	20.3	Wood	164.68	
Total IPP	**73.69**		**321.12**	

The most significant result of Rule 4.100 was the creation of a single purchasing agent, the Vermont Electric Power Producers, Inc. (VEPPI), which was recently awarded the contract to administer the state program, replacing the Vermont Power Exchange (VPX). VEPPI aggregates most of the power produced by the QF's in Vermont and wholesales it on a pro rata basis to all Vermont distribution utilities. Through a statewide lottery, projects were awarded the right to sell to the VEPPI based on projected statewide-avoided costs. These sales contracts have terms of 20 or 30 years. The current Rule 4.100 is potentially in conflict with recent developments in transmission policy created by Federal Energy Regulatory Commission (FERC) Order 888. Under this order, companies transmitting power must post their rates for all to see and users of transmission facilities must make reservations for that use. Both of these provisions do not really work with the current Rule 4.100 system. Efforts to revise the rule have not been vigorously pursued. Until recently, there has been little activity from IPP developers. As new projects are presented to Vermont utilities they are not being offered through the purchasing agent system, but generally are being purchased by the host utility at a price indexed to the prevailing clearing price at the point of interconnection.

Table 4-3

Vermont Renewable Energy Generating Capacity

Facility	Capacity MW
Small Hydroelectric	
Utility-owned	84
Independently-owned	54
Total Small Hydroelectric	138
Wood	
McNeil	53
Ryegate (QF)	20
Total Wood	73
Landfill Gas	3.6
Wind	6
Total Renewable Generating Capacity	**220.6**

The cost of IPP power contracts has been a serious issue. Replacing the existing QF power purchased through the purchasing agent with power purchased from the New England wholesale market would currently cost about 4.5 cents/kWh. The average QF contract power is priced at about 13 cents. The over all market cost is therefore about 7.5 cents/kWh or 25 million dollars per year. The total electric bill for Vermont is about 650 million dollars, so these above market costs represent approximately 4% of electric bills. One way to mitigate these costs is through securitization. In the 2001 session, the Legislature passed a bill authorizing securitization that is a financial tool whereby contracts can be bought out or bought down to a lower level. Under this approach, Vermont or some other bonding authority would issue bonds, the proceeds of which would be paid to producers in return for lower rates. Since Vermont would be issuing the bonds, very favorable bond rates would result in substantial savings relative to current QF price levels. The utilities are also pursuing other mitigation measures. Docket 6270, which recently concluded, resulted in a series of measures that will result in roughly three million dollars in price concessions from QF's. These concessions were achieved largely through elimination of various performance and insurance requirements that were designed to ensure QF's continued operation throughout their entire contract periods.

EFFICIENCY UTILITY

The efforts of Vermont at procuring resources from energy efficiency are fully detailed in Chapter 6. To the extent that resources are freed up as the result of Demand Side Management (DSM) activities, those resources are able to serve other load, thus extending the usefulness of the existing supply network and avoiding investments in generation, transmission and other supply related infrastructure. The impacts of DSM activities are reasonably measured and able to be forecasted and they can be incorporated into supply planning exercises and decision-making processes. Efforts to integrate DSM planning into the planning of Vermont utilities appears to bring new challenges.

ELECTRIC RESOURCES OUTSIDE OF VERMONT

HYDRO QUÉBEC (HQ)

The Hydro-Québec-Vermont Joint Owners (HQ/VJO) Contract

In 1990 the PSB approved a 30-year agreement between a group of eight Vermont utilities, known as the Vermont Joint Owners (VJO), to purchase additional long term baseload power from HQ and to make it available at wholesale to the rest of Vermont's utilities. This HQ/VJO contract provided for increasing purchases of power from 51 MW in 1994 to approximately 310 MW in 2001 as shown in Table 4-4. Part of this power was to replace a 150 MW contract with the DPS and other medium term contracts signed between Vermont utilities and HQ in the 1980s. The remainder was intended to cover expected load growth. The contract requires the VJO to take energy at an annual capacity factor of 75%. Its capacity cost, based on the projected carrying cost of a new coal unit, remains fixed for each 20-year contract schedule once delivery begins under that schedule. This contract is a take or pay arrangement, meaning that regardless of whether the Vermont utilities have the need for the power for which they have contracted, they must still pay for it. (Wholesale power markets provide Vermont utilities the opportunity to resell excess HQ power.) Currently the average cost of the HQ/VJO power is about 6.5 cents/kWh, which puts it somewhat above the cost of market alternatives in 2004. HQ/JVO power is stably priced, immune to escalating fossil fuel prices and retrofit costs and does not contribute to the air quality problems of our region.

Hydro-Québec Supply Reliability

Vermont imports most of its HQ power through a converter in Highgate owned by the VJO.[8] In 2001, this interconnection was upgraded to handle 225 MW. Much of the remaining HQ power is brought into Vermont through direct transmission links with Québec and is maintained by the Vermont Electric Cooperative (VEC). These two pathways, the Highgate converter and direct links to Québec, are not sufficient to bring in all of the power scheduled to arrive under the HQ/VJO contract. Purchasers of HQ/VJO power also need to make use of the High Voltage DC (HVDC) interconnection between Québec and New England. Vermont utilities own 183 MW of capacity on this 2,000 MW transmission line, which runs from Des Cantons, Québec to a converter in Sandy Pond, Massachusetts. Vermont's entitlement in the HVDC line is more than enough to import the HQ/VJO power not brought in through Highgate or block loaded.

[8] Since HQ's electrical system is not synchronous with the U.S. system, it is necessary to convert the electricity to Direct Current (DC) and back to Alternating Current (AC) before it can be used on the northeastern electric grid. This is done at Highgate, Vermont. Converters also exist at Sandy Pond, Massachusetts and Chateauguay, Québec. Alternatively, certain territories near the Canadian border can be disconnected from NEPOOL and linked directly to the HQ system. This is called block loading. Several Vermont towns have received service directly from the Québec system for decades.

Table 4-4

Vermont Purchases from Hydro-Québec			
	MW	**Start**	**End**
DPS Highgate Contact	150	Sept.1985	Sept. 1995
HQ/VJO Contract			
Schedule A	41	Nov. 1990	April 1, 1991
	20	May 1, 1991	April 1, 1992
	19	May 1, 1992	Sept. 1995
Schedule B	176	Oct. 1995	Oct. 2015
Schedule C1	51	Nov. 1990	April 1, 1991
	54	May 1, 1991	Aug. 1991
	55	Sept.1991	Sept. 1991
	25	Oct. 1991	Oct. 1995
	24	Nov. 1995	Oct. 1996
	30	Nov. 1996	April 1, 2012
	55	May 1, 2012	Oct. 2012
Schedule C2	7	May 1, 1992	Oct. 1996
	27	Nov. 1996	Oct. 2012
Schedule C3	47	Nov. 1995	Oct. 2015
Schedule C4a	25	Nov. 1996	Oct. 2016
Schedule C4b	5	Nov. 2000	Oct. 2020

Note: HQ/VJO participating utilities include: Barton, Central Vermont, Enosburg, Green Mountain, Hyde Park, Johnson, Ludlow, Lyndonville, Morristown, Northfield, Orleans, Rochester, Stowe, Vermont Marble, VEC (through the former Citizens), WEC.

All power purchased from HQ is system power that is not tied to any single unit. Since the power is supplied from many generators, its reliability is based on HQ's total system reliability. The risk associated with the VJO 310 MW system purchase is considerably lower than the risk of purchasing an entitlement of comparable size in a single unit.

Although both the DPS and HQ/VJO contracts purchase system power, their delivery over a few large interconnections raises some of the same issues of size and risk associated with purchases of power from large generation units. The risk is mitigated by the fact that transmission facilities generally have a much higher reliability than generation facilities and the existence of surplus interconnection capacity on the HVDC line. In addition to the Highgate and the HVDC interconnections, Vermont can, and sometimes does, utilize the interconnection between Chateauguay, Québec and New York to import power. The existence of this potential alternative path further reduces the risk of failure of one of Vermont's primary interconnections with Québec. Of course, since each utility's level of dependence on this source varies, over reliance may be a risk for some. Still, the ice storm of 1998 showed that transmission lines can be vulnerable as well. Events in the winter of 2004 further demonstrated that even this system power is not immune to reliability issues.

On January 15, and 16, 2004, due to expected extreme high peak loads, HQ asked for relief in advance and a portion of the power contract with Vermont was transferred from the Highgate tie to a delivery point in Maine. This left a minimum necessary 100 MW scheduled for delivery through the Highgate tie on January 15 and 16. The risk of possible loss of load in Vermont increased when the 120 kV line from Québec to the Highgate Converter tripped at about 2:15 AM on January 16th. This line, and therefore the Converter, was not restored to service until 4:15 PM.

At approximately the same time, numerous generators in New England ceased working; apparently some were without contracts for firm gas supplies (or effective dual fuel capability) and others had sold gas into the market at a better margin or due to structural commitments or timing differences among the daily gas and electric markets. ISO-NE experienced very unpredictable supply conditions in the face of growing peak loads above 22,000 MW. Despite the region's very large installed generation capacity reserve margin (+30%), a large amount of generation became unavailable because of either fuel unavailability (natural gas primarily) or ineffective dual fuel capability (caused by environmental permit operating restrictions).

Both situations coincided with the New England electric system critical peak loads, nearly causing ISO-NE to call for the extreme procedure of rotating customer blackouts. Each of these situations could have led to prolonged customer outages during extremely severe winter weather in Vermont and could have precipitated a public emergency.

HQ appears to be attempting to mitigate the economic and reliability effects of the deficiencies by bringing on new production capacity and by working with Vermont utilities to partially redirect contract deliveries away from a weak part of its transmission system. The problem is that at some point redirecting deliveries has the potential to adversely impact Vermont system reliability. Furthermore, HQ's overall situation could result in them being unable to make the remaining scheduled delivery to Highgate.

Since these system issues are region-wide generation capacity and transmission system deficiencies, ISO-NE and HQ TransÉnergie, as the respective control area operators, must address them in coordination with the operators of the controllable interconnected assets.

NIAGARA AND ST. LAWRENCE PROJECTS

Since the late 1950s, Vermont has had the benefit of obtaining inexpensive power from the New York Power Authority (NYPA) and its predecessor PASNY. This power has been very inexpensive due to historical federal subsidies for hydro dam construction. Until July 1, 1985, Vermont received 150 MW of 0.2 cents/kWh energy from the St. Lawrence and Niagara hydro projects. As fuel prices soared in the 1970s, other states chose to take advantage of the low-cost NYPA power, and Vermont was forced to accept a lesser share. Under a decision by NYPA, Vermont's entitlement from the St. Lawrence project has gradually declined from 68 MW in 1985 to 1 MW by 1994. Vermont's entitlement to the Niagara project's power has also been reduced as a result of litigation; its year 2004 share is 11.2 MW. Even at this reduced level, the price continues to make this energy attractive to Vermont.

WHOLESALE POWER MARKET

As discussed briefly in Chapter 2, the landscape for electric power dispatch and transactions changed dramatically in 1999 with the creation of the Independent System Operator for New England (ISO-NE), soon to be organized as a Regional Transmission Organization (or RTO-NE).[9] The ISO-NE is a not-for-profit organization with responsibility for administering the regional wholesale electric power market and for operating the high voltage electric transmission system. Although the details of the wholesale market system have been continually evolving since that time, this fundamental change abandoned the prior system where dispatch was based on the marginal operating cost of the next available unit, and replaced that system with one where owners of generation bid their units into a clearing market.

With the development of this bid-based market, most of the vertically integrated utilities in New England sold their generating assets to independent generation companies. These generating companies had no retail load to serve, contracting instead with Load Serving Entities (LSE) to provide energy or selling it into the wholesale market.

Chapter 7 discusses the features of the Standard Market Design (SMD) that govern power transactions in New England. From a power supply standpoint, Vermont utilities make extensive use of the market for various products at various times throughout the year. Having the market and being able to rely on it is essential to providing reliable and low-cost service to customers. The restructured wholesale market has produced a host of new energy products available for integration into a resource portfolio. The most common means of conducting transactions in short-term power deals is by contracting for a strip, which is a 100% capacity factor block of power that can be purchased for peak or off peak hours in a day. They may be purchased for periods as short as one hour and for periods as long as several years. The energy in these strips is provided from the seller's portfolio of resources and is sold at a predetermined cost. These strip transactions are not tied to specific resources, but rather are tied to the resource portfolio of the seller. In addition to energy, LSE's are responsible, on an hourly basis, for having sufficient capacity and reserve products to cover their load. In addition to energy, these products are Installed Capacity, three types of reserves and Automatic Generation Control (AGC). These products are provided by owned generation, purchased from owners of other generators or procured on the hourly market.

UTILITY CAPITAL REQUIREMENTS

The development of active and effective wholesale markets and purchase power arrangements may be fundamentally altering the extent to which utilities must rely on owned-generation to meet their own customer loads. Only a few years ago, the Vermont mix depended on owned generation. Today, most of the Vermont mix is met through purchase power form merchant generation. Vermont utilities will, however, need to maintain ready access to capital by maintaining solid bond ratings in order to preserve options to build generation and to meet the requirements for delivery of required transmission and distribution, when needed. (See the discussion in Chapter 10 concerning access to low-cost capital.) Municipal and bond banks continue to rely on the municipal bond bank for low cost capital.

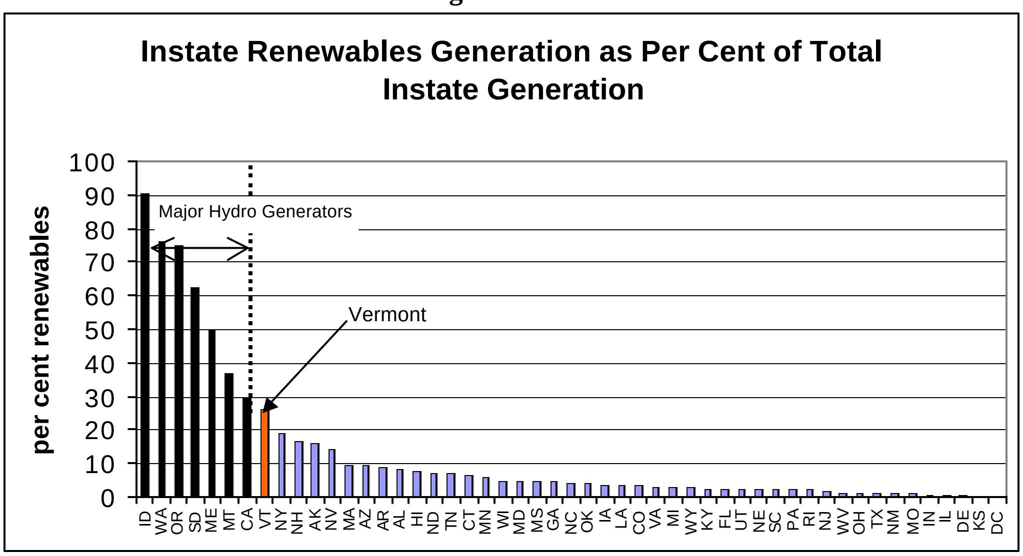
[9] In 2004, the ISO became a Regional Transmission Operator, (RTO). This is discussed in Chapter 7.

ENVIRONMENTAL PROFILE OF VERMONT'S CURRENT ENERGY PORTFOLIO

Vermont's electric generation portfolio is among the most environmentally benign portfolios in the U.S. Vermont is among the national leaders in the percentage of renewable energy generation in its in-state resource mix (See Figure 4-2). Renewable energy means energy produced using a technology that relies on a resource that is being consumed at a harvest rate at or below its natural regeneration rate.[10] Approximately 26% of Vermont's in-state generation comes from renewable sources. Of Vermont's total annual energy demand, 12% – 15% is produced from renewable generation sources. This percentage varies from year to year mainly due to fluctuations in water availability for hydro generation. Load supplied by HQ is not considered renewable under Vermont statute. Even though emission profiles are identical for large and small hydro, generation over 80 MW is considered large hydro and therefore excluded.[11] Including HQ as a renewable would bring the Vermont portfolio total to approximately 50% renewable sources.

Vermont also compares very favorably to other states when one looks at emissions of air pollution and greenhouse gases from in-state electric generation. (See Figures 4-3 and 4-4.) Based on the aggregation of emissions of sulfur dioxide (SO_2), carbon dioxide (CO_2) and oxides of nitrogen (NO_x), Vermont's in-state generation produces only 0.06 tons of emissions per MWh generation.[12] This compares to a national average of 1.42 tons per MWh or approximately 96% less than the national average. The remaining 49% of Vermont's load is from out-of-state generation of which 71% is non-emitting hydropower from Canada. Contributions to U.S. air emissions from Vermont's in-state generation constitute less than 2/10th of 1% of NO_x, 1/10th of 1% of SO_2, and 7/10th of 1% of the greenhouse gas CO_2.

Figure 4-2



[10] 30 V.S.A. § 8002 (2)

[11] 30 V.S.A.§ 8002 (2) (C) For purposes of this chapter, the only energy produced by a hydroelectric facility to be considered renewable shall be from a hydroelectric facility with a generating capacity of 80 MegaWatts (MW) or less.

[12] The Vermont Yankee (VY) nuclear plant has radioactivity emissions during normal operation of no greater than 20 mrem/year, which is less than the federal limit of 25 mrem/year.

SUMMARY

Vermont's utilities both own and contract for generation to serve their customers. Vermont is part of an interconnected network of power suppliers, both in and out-of-state. Figure 4-5 shows how the power supply mix has changed over the past 12 years and shows past peak power demand. It continues that line with a projection of future peak power demand and it also shows the mix of resources that have been committed to Vermont to meet that demand, along with those that are committed to the state in the future. That mix has been high in generation sources with relatively low environmental impact compared to many other states. Although the composition of portfolios varies among Vermont's retail utilities, in general, aggregation of Vermont committed units or contracts covers approximately 85% of the state's energy needs until the VY contract expires in March 2012. Following the expiration of this contract is the ramping down of the HQ contracts through 2016.

Figure 4-5 shows an approaching gap in the supply of Vermont's electric power. The future gap in the size of anticipated peak load and committed supply does not foretell a crisis, but it does illustrate the need to make important choices now and in the years to come.

Figure 4-3
Vermont's Comparative Pollution Emissions

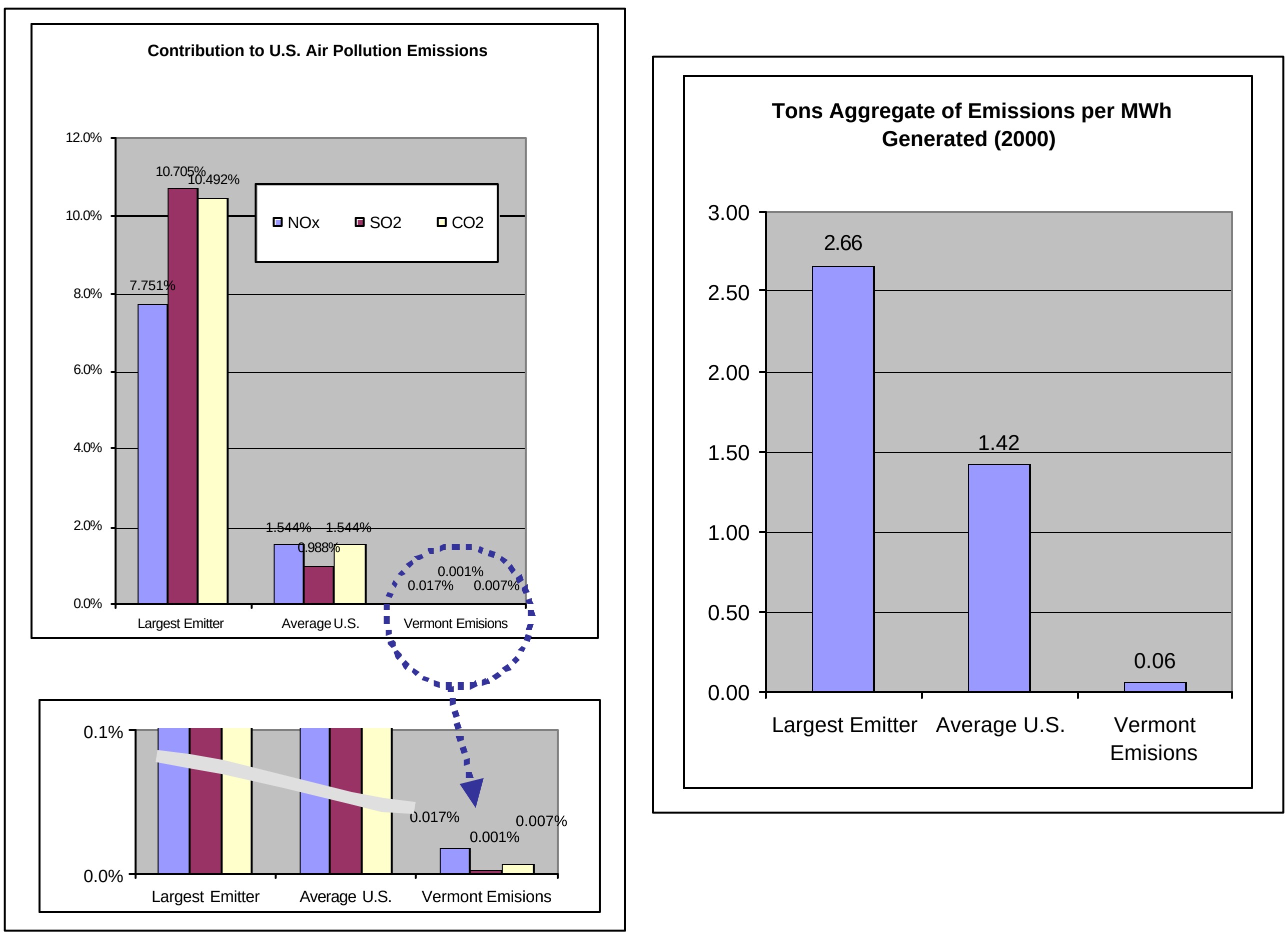
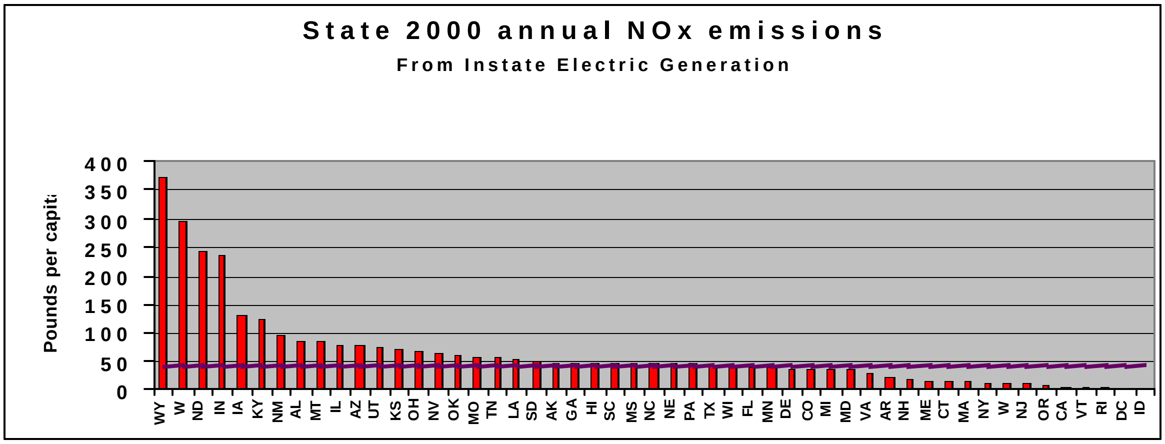
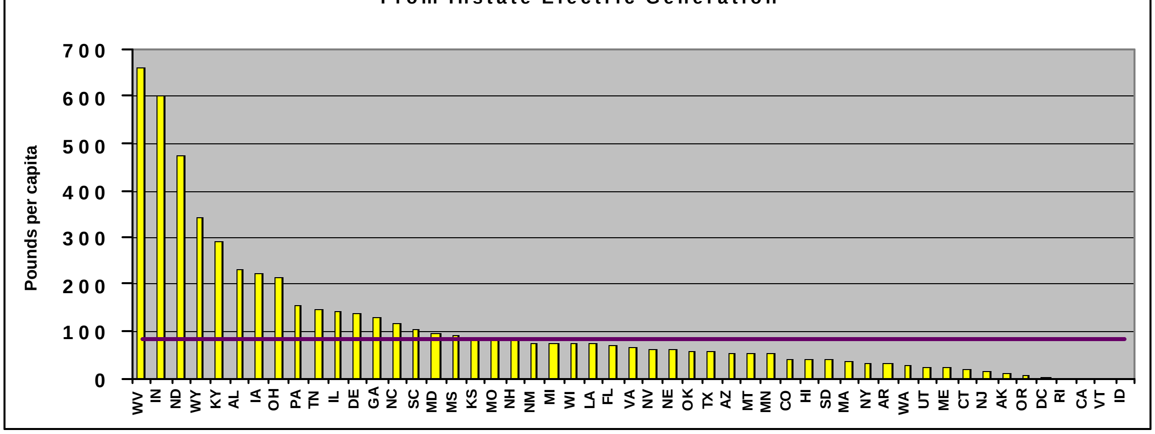


Figure 4-4


State 2000 annual NOx emissions
From Instate Electric Generation
Pounds per capit
400
350
300
250
200
150
100
50
0
WY W ND IN IA KY NM AL MT IL AZ UT KS OH NV OK MO TN LA SD AK GA HI SC MS NC NE PA TX WI FL MN DE CO MI MD VA AR NH ME CT MA NY W NJ OR CA VT RI DC ID


State 2000 annual SO2 emissions
From Instate Electric Generation
Pounds per capita
700
600
500
400
300
200
100
0
WV IN ND WY KY AL IA OH PA TN IL DE GA NC SC MD MS KS MO NH NM MI WI LA FL VA NV NE OK TX AZ MT MN CO HI SD MA NY AR WA UT ME CT NJ AK OR DC RI CA VT ID

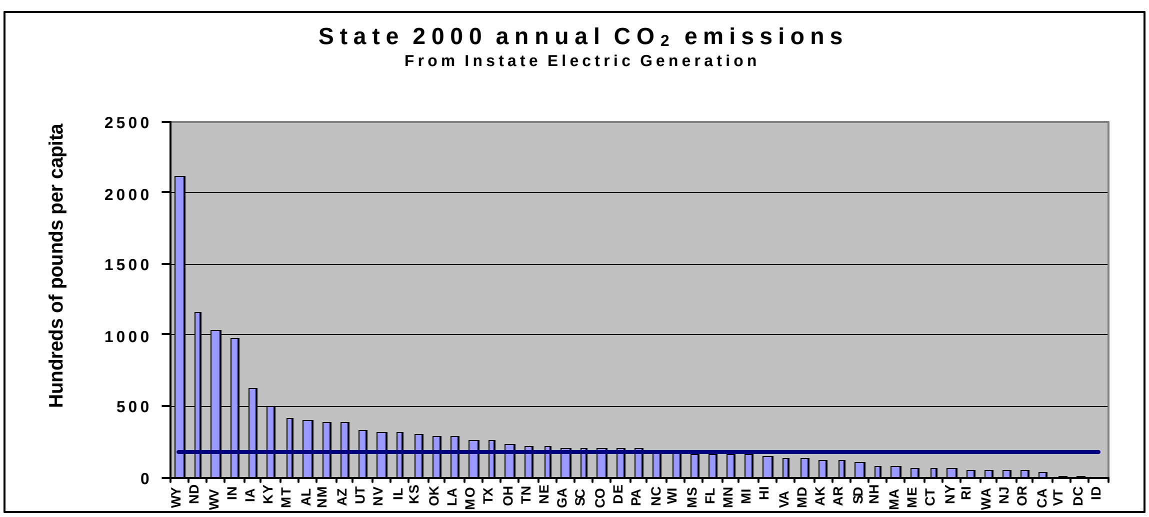
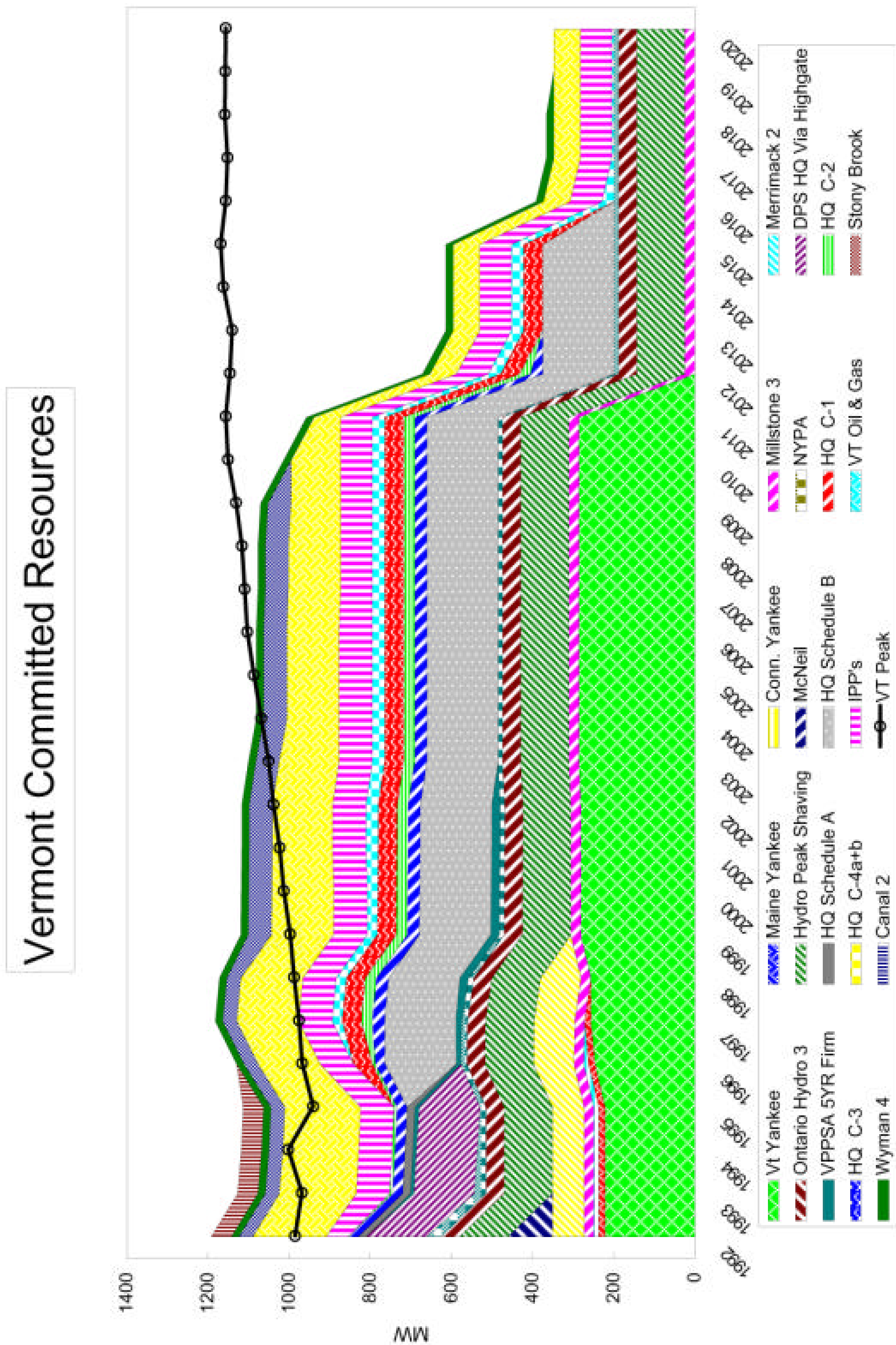

State 2000 annual CO2 emissions
From Instate Electric Generation
Hundreds of pounds per capita
2500
2000
1500
1000
500
0
WY ND WV IN IA KY MT AL NM AZ UT NV IL KS OK LA MO TX OH TN NE GA SC CO DE PA NC WI MS FL MN MI HI VA MD AK AR SD NH MA ME CT NY RI WA NJ OR CA VT DC ID

Figure 4-5


Vermont Committed Resources
MW
1400
1200
1000
800
600
400
200
0
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
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2007
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2013
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2016
2017
2018
2019
2020
Vt Yankee
Ontario Hydro 3
VPPSA 5YR Firm
HQ C-3
Wyman 4
Maine Yankee
Hydro Peak Shaving
HQ Schedule A
HQ C-4a+b
Canal 2
Conn. Yankee
McNeil
HQ Schedule B
IPP's
VT Peak
Millstone 3
NYPA
HQ C-1
VT Oil & Gas
Merrimack 2
DPS HQ Via Highgate
HQ C-2
Stony Brook

CHAPTER 5: Emerging and Sustainable Energy Technologies

INTRODUCTION

We can and must make choices as to the sources of our electric energy over the next 20 years. The choices we make will depend on our objectives, the goals we establish, and how we weigh those goals. In some cases individual users of electricity may make those choices. Whereas most individuals and businesses will remain connected to the integrated electric grid, supplied by their local distribution utility, some may choose to be totally independent by installing their own on-site generation, while still others may choose to be partially independent through net metering arrangements and/or participation in voluntary green pricing programs.

It is also important to remember that the main focus of this Plan is on decisions that must be committed to today or in the near future. In general, we do not have to commit today to a potential decision far into the future. For example, utility resource plans often include generic resource additions ten or twenty years from now. Such resource decisions are irrelevant if they require no action whatsoever today. This does not mean we ignore the future, it simply means we identify decisions that must be made today, even if such decisions simply preserve options for us in the future.

However, in the case of emerging technologies, an additional assessment may be necessary to determine if these technologies represent options with future commercial potential. Making this determination may be relevant to the type and level of market intervention or assistance that may be warranted, and ultimately, the resources available at critical decision points in the future.

This chapter reviews a number of alternative generation technologies that exist today and, in some applications, are already cost-effective, including wind resources, solar, and biomass. We also review a number of technologies that are potentially viable in the future. While not cost-competitive today, these technologies hold a promise of greater efficiency and lower environmental impacts than today's generating technologies. We conclude this chapter with a discussion of net metering, (a program to encourage small-scale renewable development) and green pricing programs (that allow individual customers to select the environmental attributes of the electricity they purchase).

RENEWABLE RESOURCES

Renewable resources differ from finite resources (such as nuclear and fossil fuels like coal, oil, and natural gas) in many ways, foremost being that renewable resources are sustainable. Renewable resources can be more costly in terms of first cost, but provide other benefits that are important to consider. For example, renewable resources provide the benefit for all intents and purposes of never-ending power. Additionally, some renewable power systems, once the cost of construction and maintenance are taken into account, have no fuel costs. Solar and wind generation are two prime examples. Others, such as wood-fired generating stations, like the McNeil and Rygate power plants, provide power from native harvested wood chips at a relatively low-cost relative to current wholesale market conditions. Renewable resources provide another benefit that their finite fuel counterparts do not -- they can be found locally. This aspect in itself provides benefits because when fuels can be obtained locally, the dependence upon other countries such as those in the Middle East becomes less of an issue therefore some risk is eliminated. Fuel transportation costs and the associated environmental impacts are reduced or eliminated and local jobs and businesses may be created giving a boost to the Vermont economy.

Northern New England, with its ample forests, windy ridge-tops and numerous rivers would appear to have an advantage over other New England states in their ability to produce renewable energy. This fact should not be lost on policy makers. It is likely that the three northern New England states could meet a significant share of the renewable resources necessary to serve the needs of the region. Further, Vermont has a significant number of renewable energy based businesses with the ability to serve a developing market for both residential and utility sized applications.

In general renewable resource technologies can be applied at the local, or building level, providing electricity and energy to one or two facilities, or in a larger scale, at the utility level, providing electricity to the utility grid where it can provide service to many different uses. The size of utility type resources is obviously much larger than that of home size resources, however, each can have its place in the energy future of Vermont.

Since the passing of Vermont's net metering law, V.S.A. § 219a, there has been an increase in installation of small-scale renewable electric generation systems in the state of Vermont, such as small wind (smaller than 100 kiloWatts (kW)) and photovoltaic systems. This trend will likely continue. There has also been an increasing interest in large wind systems (greater than 100 KW). The Vermont Department of Public Service (DPS) will continue its support of these technologies where appropriate.

RENEWABLE ENERGY AND THE VERMONT RESOURCE MIX

Vermont's portfolio already reflects the attributes of a stable and sustainable resource mix. Roughly 15% of the Vermont mix is comprised of relatively small-scale renewables and roughly 35% of the mix is comprised of system energy from Hydro-Quebec. The HQ power relies predominantly on large-scale hydro generation. All told, Vermont already has a renewable mix with either owned or contracted features that distinguish it from the regional mix that is heavily dependent on fossil fuel sources. As measured by capacity, the regional mix is 13% renewable.[1]

ESTABLISHING STATE GOALS FOR RENEWABLES

Goals for the advancement of renewable technologies typically center on (1) advancing the commercialization of technologies, like wind, that are close to the market, or (2) promoting the advancement and development of technologies that have more long run potential, but still remain relatively far from commercial potential. Renewable portfolio standards are often presented as a mechanism for advancing the commercialization of technologies, but can serve dual objectives through "set-asides". Funds and tax incentives are more frequently tied to flexible application or

[1] The capacity factor is, however, probably below the average capacity utilization of resources in the region. Therefore, the proportion of energy is probably below the 13% regional capacity.

targeting of specific technologies.

As noted above, Vermont already has a stable and sustainable resource mix, however defined. Even when measured by the yardstick of small source renewables, Vermont is ahead of the region. Long-term goals for renewable energy may appropriately be set in relation to the regional market in which Vermont fundamentally depends. The comparative advantage of Vermont should not be lost as Vermont considers strategies and goals for renewable energy.

Solar

The biggest fuel of all is the sun. Virtually all energy sources on earth are derived from the sun's radiant energy. It's hydrogen gases have been going through massive nuclear fusion reactions for billions of years, releasing all the heat and light energy that our solar system depends on. Radiation from the sun makes the wind blow, heats the surface of the earth, and causes water to evaporate and condense, creating precipitation. Hydroelectric and wind power are technologies that harness forces originally created by the sun by converting the movement of wind or water to electricity. The force of both water and wind can be used to spin turbines, which in turn generate electricity, and can be used by homes, institutions, and businesses. Solar radiation captured through the use of photovoltaic (PV) panels can be used to generate electricity directly. The heat created by solar radiation can be used to heat buildings with the use of passive solar design techniques. Also, this heat can be utilized by domestic and forced hot water heating systems.

Small Scale Technologies

Passive solar heating and lighting for buildings is a common application of renewable energy. Day-lighting is the use of direct, diffuse, or reflected sunlight to provide full or supplemental lighting for building interiors. Artificial lighting accounts for as much as 40% to 50% of the energy consumption in many commercial and institutional buildings and 10% to 20% of energy consumption in industry. Day-lighting can significantly reduce artificial lighting requirements and energy costs in many commercial and industrial buildings, and institutional facilities such as schools, libraries, and hospitals. Day-lighting, in combination with energy-efficient lighting, reduces the lighting power density in some office buildings from 2.2 W/ft^2 (23.7 W/m^2) to 0.88 W/ft^2 (9.5 W/m^2) without a reduction in the measured lighting levels (in foot-candles at the work surface).

A passive solar heating system collects energy from the southern exposure and uses this energy to heat a space directly, or to heat a fluid that later radiates heat to a space. Orienting the building with an east-west configuration so that the majority of the window glazing has a southern exposure can do this. High quality insulated glass, insulated window shades, and so-called super insulated walls, ceilings, and floors can be installed to reduce the building's heat loss. The strategy of constructing to minimize building heat loss and designing it to capture available solar energy can not only save on heating fuel costs, but also reduce electric use from heating auxiliaries such as fans or pumps.

Photovoltaic (PV) systems-are another way of capturing the sun's energy. These systems use solar cells to directly produce Direct Current (DC) electricity from solar radiation. DC power must be converted to Alternating Current (AC) for ordinary household appliances to use. This is done through the use of a device called an inverter. Solar cells can be integrated into roofing systems to utilize a large surface area and sometimes into roof shingles that are indistinguishable from standard roof shingles. Some manufacturers offer DC powered appliances such as attic fans and well pumps that avoid the need of the owner to purchase an inverter and the associated conversion power losses.

Some homes, institutions, and businesses use active solar systems to reduce the amount of power they buy from the electric utility. Some configurations feed power directly back to the utility grid during times where the system produces excess power. The utility meter actually spins backwards when this occurs. These systems are termed “net metered” because utility customers are able to effectively sell power back to the utility at retail, not wholesale rate when they have excess power. Other systems use the solar cells to charge batteries. Power from the batteries is used for house or building power. These systems can be designed to interconnect to the utility grid in a net-metered arrangement or be independent of the utility distribution system, called off-grid. These systems require the use of batteries to provide power during nighttime hours and when clouds obscure the sun. With some hybrid systems, two renewable sources are used, active solar and small wind systems.

PV systems are used in other applications where traditional electric power supplies are not needed, wanted, or cost effective. Currently in Vermont, PV systems are being used to provide power for street signs, monitoring stations, highway construction signs, off-grid homes and many on-grid homes and businesses. PV systems have also been used to power DC well pumps to provide water in remote camping areas where installing a utility line extension is cost-prohibitive. Some cars also use photovoltaic cells to power electric motors. These specialized applications should be encouraged both as cost effective solutions in their own right and as a vehicle for integrating distributed generation sources into the mainstream electric supply.

At this time, photovoltaic systems are relatively expensive on a dollar per kilowatt-hour (kWh) basis. As an example, when taking into account all of the costs of building and maintaining an active solar system over its lifetime, the customer cost per kWh is about 20-50 cents/kWh. Compare that to the Vermont average retail residential rate per kWh of 12.9 cents. However, photovoltaic systems can be cost-competitive as an alternative to installing a utility line extension. Also, their equipment costs have been coming down over time. PV systems exhibit characteristics that are important for planners to consider. Since their output is proportional to the intensity of the sunshine, it tends to be coincident with summer peak load conditions that are driven by air conditioning.

Utility Scale Technologies

Solar thermal electricity is generated often by concentrating the sun’s rays on a small surface in order to boil water and generate steam. The steam that is created is used by a turbine to generate electricity. Curved mirrors are often used to concentrate the sun’s radiation. Most of the world’s solar generated power is derived from solar thermal electric power plants. This technology has been in use for about 20 years but its high cost per kWh (10-15 cents/kWh[2]) is a barrier in addition to the limited areas where it can be installed and cloudy locations diminish cost effectiveness dramatically.

WIND

The windmills that dotted the landscape of Europe and the Middle East since the tenth century have evolved into wind turbines, sleek machines capable of producing electricity to be delivered to homes and businesses in Vermont. The power output has evolved as well, from the original direct drive applications used to grind and mill grain, to electric power which can be used in motors to accomplish the same milling and grinding or be used to power the many appliances of modern life. In the U.S. and worldwide, wind generated electricity is the fastest growing segment of renewable energy production. Spurred by cost reductions and improved reliability from turbines, depending on site-

[2] Solar Thermal Power Generation Technology Scan

specific factors, utility scale wind energy is cost competitive with traditional electricity sources before accounting for externality values or Renewable Energy Certificates.

Utility Scale Technologies

A 1991 report by the Department of Energy (DOE) estimated that Vermont had a theoretical wind energy potential of 537 MW. A more recent report by the DPS suggested that there could be as much as 759 miles of potential utility scale wind sites on the ridgelines of Vermont.[3] Among the barriers to development of wind power in Vermont are environmental and site constraints, aesthetic concerns, and regulatory issues concerning siting and operational permitting. Information provided by Renewable Energy Vermont suggests that there are at least 137 MW of utility-scale electric projects available for development within Vermont (covering at least 7 locations) capable of producing 360 GWh of electricity (roughly 6% of annual electricity consumption in Vermont).

The prospect for increases in the use of wind power in Vermont for utility-scale generation of electricity in Vermont has led to heightened debate over project proposals. According to the Department of Energy, wind energy is the fastest-growing type of energy generation in the United States and around the world. Global wind energy capacity reached 31,000 MW by the end of 2002.

The United States had almost 4,700 MW of installed wind energy capacity, enough to power almost 3 million average homes. Utility-scale wind power plants are now located in 27 states. The average U.S. wind energy growth rate for the past five years is 24%. This growth can be attributed to a greatly reduced cost of production (from 80 cents [current dollars] per kilowatt-hour [kWh] in 1980 to 4 cents per kWh in 2002).

Costs, Environmental Impacts, and Other Characteristics of Wind Power

Wind energy is one of the lowest-cost renewable energy technologies available today, costing between 4 and 6 cents per Kilo Watt-hour (KWh) on average across the nation, depending upon the wind resource and financing of the particular project. In Vermont, wind installations tend to be somewhat more expensive than average, due to the challenges of installing turbines on mountain tops and the costs of transmitting that energy to the grid. Because the fuel (wind) is free, wind energy can provide a stable long-term price for power production and, as a result, has been the focus of developers throughout the region. The cost of electricity generated by modern wind farms has declined by 80% since 1980 and is expected to continue to decline as the technology improves and the market for this source develops.

A 1.5 cents per KWh federal production tax credit for electricity generated from wind turbines in the first ten years of operation has helped make development of wind power projects across the country more economically viable and has contributed to increased development of wind energy. That credit, which was raised to 1.8 cents per kWh to adjust for inflation, was critical to projects hoping to win financing from lenders. Uncertainty about the tax credit, which expired on December 31, 2003, reduced the rate of growth of wind power nationally from 1,700 MW of new production capacity in 2003 to an expected 500 MW of new generation in 2004. The tax credit, first adopted in 1992, expired in June 1999, then was renewed six months later in December 1999. It then expired in December 2001 and was re-implemented in March 2002. [4] The credit was recently renewed on

[3] Wind Generated Electricity History and Assessment, DPS, January 15, 1994

[4] Ken Silverstein, PacifiCorp Ventures Indicate Wind Power is Economically Viable, RiskCenter.com, May 14, 2004

October 4, 2004 as part of the Working Families Tax Relief Act. The tax credit was renewed through December 31, 2005 and made retroactive to January 1, 2004.[5]

The sale of Renewable Energy Certificates (RECs) can further enhance the economics of a wind installation for a developer or utility. Each MWh of electricity generated by a wind facility creates a REC. These RECs are used by load serving entities to demonstrate compliance with requirements arising from Renewable Portfolio Standards (RPS) adopted by their states or as documentation for "green" energy products they may be offering. Currently certificates from a newly constructed wind (or other qualifying renewable) facility are currently selling for about 4 cents per kWh – a significant incentive to aid in the development of wind facilities.

The "fuel" for a wind turbine is wind, so its air emissions are zero. Electricity generated by wind turbines will not emit air pollutants like most other energy sources—that means less smog, less acid rain, and fewer greenhouse gas emissions. Power plants are the largest stationary source of air pollution in the U.S., emitting millions of tons of sulfur dioxide, nitrous oxides, and carbon dioxide each year. Every KWh generated by a wind turbine will offset one that would have been generated by a fossil fuel source.[6] Running a single 1-MW wind turbine can displace 2,000 tons of carbon dioxide in one year (equivalent to planting one square mile of forest).

Since the wind is an intermittent resource, much like run of river hydro plants, it must be integrated into a portfolio of resources. A run of river hydro plant only generates as much energy and at such times as the inflow to pond behind the dam allows. As with wind, this generation can be forecast with some margin of error for a few days ahead. All energy sources have some variation in their level of output. Financially these fluctuations are managed by utilities by having a diverse portfolio of resources. From a reliability standpoint, these variations are managed by having enough reserves available to system operators to handle the myriad of instantaneous changes in availability of supply sources or level of load in the region. From a system stability standpoint, fluctuations in output from resources like wind or hydro are similar to issues routinely faced by system operators such as fluctuations in load or sudden loss of a large generation unit. The power grid has been designed with these kinds of variations in mind. It is able to accommodate everything from a single electric motor starting in Burlington, to the sudden loss of output from Vermont Yankee (VY) in Vernon. Wind should be viewed as a component in a balanced portfolio of resources that can importantly act as a hedge against fluctuating fossil fuel prices.

In Vermont, the windiest sites are located on the North-South ridgelines. These locations are often in remote areas, far from the load centers where the electricity will be consumed. The most desirable ridgelines are above 2,500 feet in elevation. Any intrusion on the fragile habitat at that elevation must be done with extreme caution. Furthermore there are environmental concerns revolving around migratory birds and bats that must be addressed by wind developers. Currently there is disagreement about the nature and severity of these impacts. Some environmentalists say that multi-year studies are needed to determine the potential impacts of wind installations, while others claim the results from their shorter-duration studies will allow them to adequately mitigate any impacts on migratory species. In a tourist state like Vermont, the aesthetic impact of ridgeline development has been raised as a

[5] Database of State Incentives for Renewable Energy. Federal Incentives for Renewable Energy. Available: http://www.dsireusa.org, 1 December 2004.
[6] This is not exactly a one to one comparison since line losses attributable to both sources may not be equivalent at all times. However, generally, it is a reasonable assumption.

concern by many involved in the wind energy debate. This impact and its perceived intrusion on remote areas will have to be balanced with the environmental benefits of clean energy.

Wind energy has local benefits as well. Wind projects keep energy dollars in the states and communities where projects are located, they can provide a steady income through lease payments to the landowners, they pay significant property taxes and state taxes each year and create local jobs, and plant owners typically make rent payments to the landowner for the use of the land. Over the last five years, U.S. wind capacity has expanded at an annual average rate of 28%, according to the American Wind Energy Association. They also state that if the wind industry was to consistently grow at a rate of 18% per year, then 6% of the nation's electricity could be derived from the fuel source by 2020. That would result in more than $100 billion of new investment in rural America.

Permitting and Siting Wind Turbines in Vermont

Since most, if not all, the sites in Vermont (with the greatest potential for wind power generation) are located on ridgelines, the siting and permitting of these facilities is a sensitive matter. There are proposals in the planning stage for commercial size merchant wind farms whose output could serve instate as well as out-of-state customers (although to receive a permit under Section 248, the project must be shown to have a benefit to the residents of Vermont). This possibility raises important questions, including:

- Is the current regulatory approval process sufficient to review these projects?
- What are the environmental impacts of construction on ridgelines?
- Are the aesthetic impacts reasonable, and how can they be mitigated?

Historically, utility owned projects have been proposed by monopoly utilities and reviewed under §248 of Title 30 with final approval by the Public Service Board (PSB). All other commercial development has been the purview of local zoning, planning and the Act 250 process at the local and regional level. Act 250's founding, in part, was the result of wide ranging concern about unfettered ridgeline development. Section 248 incorporates many components of the Act 250 review process such as regional plan compliance and aesthetic impact.[7] There is however an explicit requirement under Section 248 that the PSB will ultimately find in favor of the overall public good. Because of the special sensitivity of Vermont's ridgelines, commercial wind power development may present special issues for the permitting process as it stands now. On July 17, 2004, Governor James Douglas appointed a seven-member Commission on Wind Energy Regulatory Policy to ascertain if the current regulatory approval process is sufficient for commercial wind energy projects. They issued draft recommendations for public comment in November 2004, including the following:

- Section 248 is the appropriate vehicle for reviewing proposed commercial wind generation projects.
- The PSB should increase public notification for proposed projects to a ten mile radius from each proposed turbine and require maintenance of a mailing list for all stakeholders who sign-up to receive meeting notifications.
- The advance notice period for filing plans for construction to municipal and regional planning commissions should be increased from 45 days to a minimum of 60 days and the PSB should develop requirements for what constitutes plans for construction.

[7] The PSB has essentially used the Quechee Test long used by the Vermont Environmental Board, which considers a project's level of harmony with its surrounding and series of tests to determine if there is an undue adverse impact.

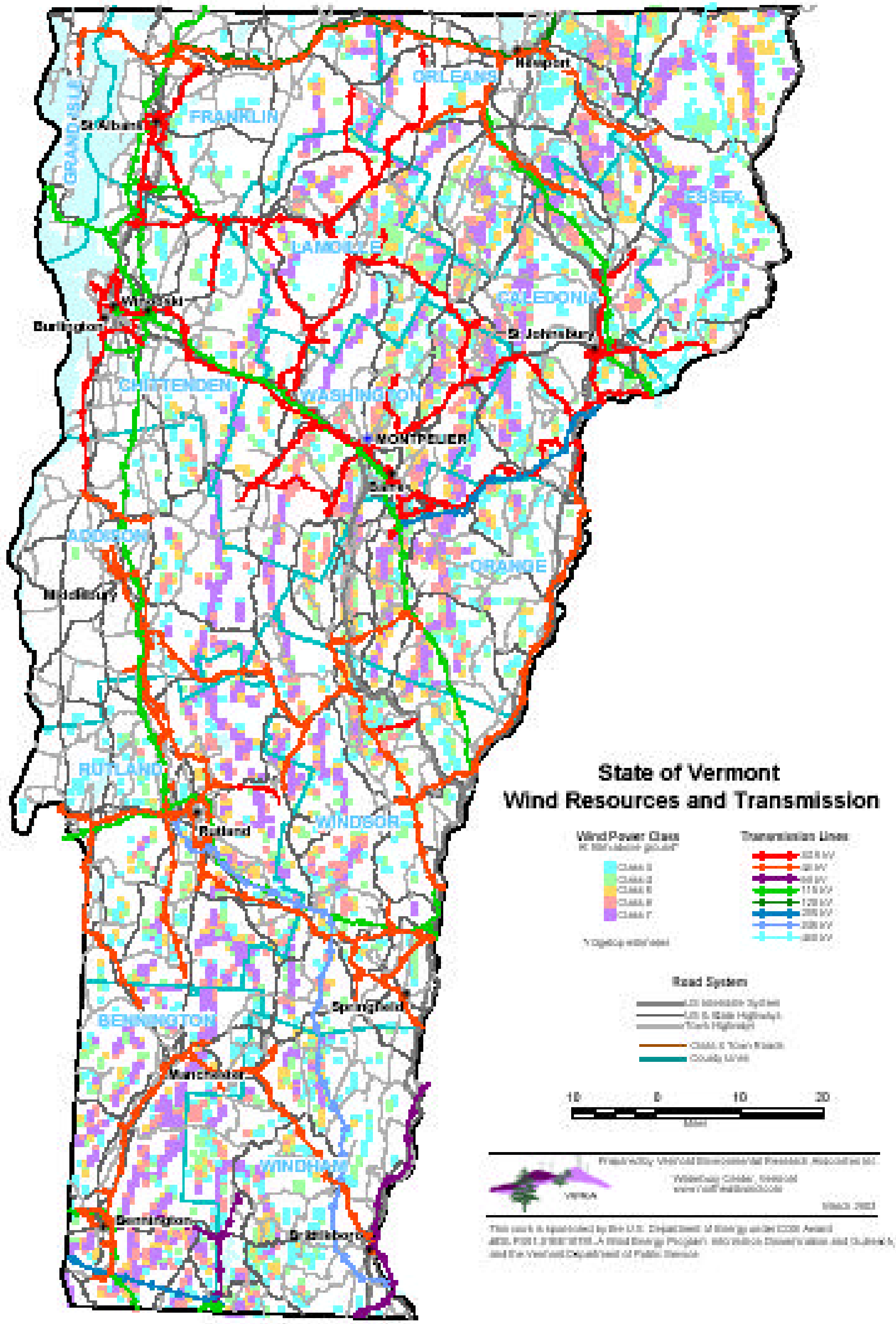
- The PSB should require wind developers to establish sufficient decommissioning funds so sites will be restored to natural conditions if the projects are not re-powered at the end of their useful life.
- An ombudsperson should be appointed to serve as a point of contact for concerned parties in the Section 248 review process.

A final report with recommendations was submitted to the Governor December 15, 2004.

These commercial wind energy proposals have also raised the issue of when to allow wind projects to use state lands, which in some cases have favorable characteristics for wind power. On December 16, 2004 Governor Douglas released, for public review, a final policy[8] on wind energy and other renewable energy development on state-owned lands. According to the policy, the Agency of Natural Resources (ANR) will more aggressively encourage and promote the development of small-scale net-metered renewable energy applications in appropriate locations on State lands. In addition, the ANR's long-range management planning process for their lands will encourage small scale, renewable energy development where appropriate on state lands under its jurisdiction, like state parks and some ski areas. The policy supports an increased focus on the development of new renewable energy sources as part of a comprehensive effort to reduce the environmental impacts of energy production. Large-scale commercial projects such as wind farms, would not be permitted on ANR lands.

[8] The policy, a summary of the public input, and other related information is posted on the web at www.vermontwindpolicy.org. Copies of the draft policy can also be obtained by contacting the ANR.

Figure 5-1 Vermont Wind Resources



HYBRID POWER SYSTEMS

A stand-alone hybrid system that combines generation sources, such as wind and PV, offers several advantages over a single fuel generation system. In Vermont, wind speeds are low in the summer when the sun shines brightest and longest, and is stronger in the winter when there is less sunlight available. Since the peak operating times for wind and PV occur at different times of the day and year, hybrid systems are more likely to produce power when you need it.

For the times when neither the wind generator nor the PV modules are producing power (like, at night when the wind is not blowing), most stand-alone systems provide power through batteries and/or an engine-generator powered by fossil fuels or through an interconnection with the grid. If the batteries run low, the engine-generator can be run until the batteries are charged. Adding a fossil fuel powered generator makes the system more complex, but modern electronic controllers can operate these complex systems automatically.

Adding an engine-generator can also reduce the number of PV modules and batteries in the system. The storage capability must be large enough to supply electrical needs during non-charging periods. Battery banks are typically sized for one to three days of operation. A general design rule is that the renewable energy system provides 80% of the energy and fossil fuels for the remaining 20%.

HYDROELECTRIC DEVELOPMENT

Hydropower is a mature electric generation technology, one that does not produce air pollution. It is not without impact on alternative uses of the stream. Those alternative uses may be more highly valued than electricity generation. Humans, flora, and fauna may lose their natural habitat as a result of a hydro plant. Local cultures and historical sites may be impinged upon. There is little likelihood that any new conventional hydro development will occur in Vermont in the future. It is more likely that a decrease in production will occur as removal of additional dams is considered (e.g., Peterson Dam) or operating conditions imposed as a result of renewing the license of existing hydro projects will reduce the available generation from our existing portfolio of hydro plants.

A different technique for harnessing energy from the flow of water is the use of kinetic energy turbines also called free-flow turbines that generate electricity from the kinetic energy present in flowing water rather than the potential energy from the head. The systems may operate in rivers, man-made channels, tidal waters, or ocean currents. Kinetic systems utilize the water stream's natural pathway. They do not require the diversion of water through artificial channels, riverbeds, or pipes, although they might have applications in such conduits. Kinetic systems do not require large civil works, however, they can use existing structures such as bridges, tailraces, and channels.

BIOMASS ELECTRIC GENERATION

Biomass is a category of organic materials that by its very nature are renewable and are used to generate electricity by either burning the material itself or gases produced from the material (bio-mass gasification). The heat produced from either of these processes is used to generate steam and finally electricity through the use of a turbine. Biomass wood energy generation, although it produces particulates and some other chemicals, produces less greenhouse gases than fossil fuel generation because of the so-called carbon cycle. This cycle is the concept that when wood is burned, the carbon given off in the form of CO_2 is equal to the amount that the wood when in tree form captured from the atmosphere during the growth process. Fossil fuels on the other hand, when burned increase CO_2 levels in the atmosphere. Vermont has two large-scale wood biomass generating facilities one in

Burlington, the other in Ryegate. These plants serve as renewable alternatives to oil or coal fired generators.

WOOD

As noted in Chapter 4, the 53 MW McNeil Station is the largest wood-fired generator in the world when it came on line. BED is considering the installation of an ammonia injection system to help improve the emissions characteristics of burning wood.

BIO-GASIFICATION

Biogas (Biogenic methane) is produced from anaerobic digestion of organic residues and wastes and contains between 55% and 80% of methane. It can be used like natural gas in a wide variety of electrical generation, or cogeneration systems. Anaerobic digestion is a biological process where organic materials are degraded by several different and distinct types of bacteria. The gas produced is collected, and in some cases stored, before being fed into a modified engine or turbine to produce power. The factors affecting the production of biogas are the biodegradable content of the organic material(s), digester retention time, and operating temperature. Using biogas to produce electricity can harness energy from sources that often otherwise would be wasted. The sources of biogas are landfills, agricultural and other organic wastes.

There is one biogas application currently operating in Vermont at the Foster Brothers farm in Addison County. Central Vermont Public Service (CVPS) is working with another farm in its service territory on installing a similar system. In relation to this work, CVPS has established a voluntary renewable tariff for biogenic methane from farm waste known as CVPS *Cow Power*™ introduced to customers in September 1, 2004. In addition to the electricity production from the wastes, the effluent from the digester is an improved and less odorous fertilizer.

Landfill Methane Gas

Landfill gas is methane produced by the natural decomposition of waste. Since methane is a harmful greenhouse gas, modern landfills are required to collect the gas and burn it, rather than letting the methane escape into the atmosphere. Using the gas to generate electricity has two important potential environmental benefits; it can significantly reduce the air emissions at the landfill itself, compared to flaring. In addition, power generated will offset the need for production and environmental impacts from fossil fuel and other non-renewable generation.

Another project for utilization of landfill methane in Vermont is being developed in Northern Vermont. Washington Electric Cooperative (WEC) is seeking approval for a project to develop a renewable energy source from a plant that will generate electricity from the Landfill Gas (LFG) being produced and collected at the state's largest landfill in Coventry, Vermont. The landfill is owned and operated by New England Waste Services of Vermont (NEWSV), a wholly owned subsidiary of Casella Waste Systems of Rutland. The goals of the project are to provide a source of long-term, stable and predictably priced renewable base-load power, and to meet a significant portion of the electricity needs of the WEC's member/consumers for up to 30 years. The facility is expected to begin generating in 2005. The expected generation in the initial stages of the project is approximately 3.2 MW, equivalent to the amount of energy the WEC was purchasing from the Vermont Yankee (VY) nuclear power plant up until February 2002. This will replace and supplement power that WEC has already been purchasing from a landfill gas facility in Connecticut under a contract that will expire at the end of 2004. Potential longer-term output is projected to approach six MW with a projected cost of less than 5 cents per kWh over 30 years. A key benefit to WEC and its members is that the cost will be stable and predictable. Other landfills in Vermont are potential targets for development as well.

Agricultural Waste and Organic Residuals

Manure management is one of the larger issues facing dairy and other farms in Vermont, as well as the agriculture and livestock industry in the U.S. Traditional techniques used to manage manure on farms are coming under increasing scrutiny. The impact of agricultural waste on the waters of Vermont is a growing concern. In 2003, Governor Douglas announced the "Clean and Clear" initiative to target available state and federal resources to address the issue. A prominent focus is on Lake Champlain and the increasing amounts of phosphorus in the Lake. Efforts to clean up both Lake Champlain and Lake Memphremagog and their tributaries is also a part of a Memorandum of Understanding (MOU) between the State of Vermont and the Province of Quebec. There is growing interest in anaerobic digestion as a technology that can reduce pollutants, odors, and methane emissions resulting from traditional manure management techniques. The U.S. Environmental Protection Agency and the U.S. Department of Agriculture's Natural Resources Conservation Service have created the AgSTAR Program, which is a voluntary program designed to encourage the use of livestock manure as an energy resource, primarily if not solely through anaerobic digestion. Today, an estimated 28 farm-based anaerobic digesters are operating in the U.S. and another ten are planned. If anaerobic digestion is used on dairy or other farms in Vermont, it will be primarily used as a manure management tool. However, a potentially large amount of organic residues or wastes are generated in Vermont, and these materials could potentially be collected, transported, processed (if necessary) and used along with manure in farm-based or cooperative anaerobic digestion systems. Following is a list of significant types of agricultural wastes and organic residuals in Vermont:

- Dairy Cow Manure generated by dairy herds.
- Other Manures generated by a variety of livestock animals that may be present on Vermont dairy farms and/or other farms or livestock facilities.
- Cheese Whey generated during the manufacturing of cheese.
- Food Processing Residuals, the non-sellable, non-marketable products and by-products, and wastewater solids generated by industries during the manufacturing, preparation, and/or packaging of food products. Although similar, food-processing residuals are distinctly different from food wastes.
- Brewery Residuals, the spent grains, yeast, or wastewater generated by breweries.
- Food Waste, uneaten food and food preparation wastes generated by residential, commercial, and institutional sources such as restaurants and school cafeterias. This category also includes that food waste generated by industrial sources such as factory lunchrooms. Although similar, food wastes are distinctly different from food processing residuals.
- Bio-solids, the solids generated by the biological treatment of municipal wastewater at public and private Waste Water Treatment Facilities (WWTFs). Although termed "solids", bio-solids may actually be in a liquid or semi-solid state. Bio-solids may be unavailable to farm-based anaerobic digestion systems due to potential regulatory concerns.

In general, this category of biomass consists of materials that are present in various types of industrial and agricultural facilities and, generally speaking, are a product to be disposed. A system that can convert products that have previously represented a disposal cost into a useful product should have value to the businesses involved. Processing wastes to generate biogas could possibly create revenue stream in the form of tipping fees charged (to accept other organic residues and wastes) in addition to the sale of electrical energy. A study[9] prepared for the DPS and Department of Agriculture in 2000 estimated the energy potential from organic residues via methane production to be 30 MW. Methane from dairy manure would account for approximately 94% of the total. Based on the assumption that there are 1,693 active dairy farms in Vermont, the overall average energy potential per dairy farm is calculated to be just below 18 kW. This appears to be a relatively small output per farm. To illustrate this point, consider Vermont's net metering law, which allow farm systems (one which "generates electric energy from the anaerobic digestion of agricultural waste produced by farming, and which is located on the farm where substantially all of the waste used is produced.") to generate up to 100 kW. The average per farm generation potential suggests cooperative or community anaerobic digestion systems may be more feasible than individual farm systems.

[9] Fehrs, Jeffrey E., *Vermont Methane Pilot Project Resource Assessment*, July, 2000.

Table 5-1

Organic Residuals and Wastes Generated, Potentially Available, and Energy Potential in Vermont [10]

ORGANIC RESIDUE OR WASTE	AMOUNT GENERATED (tons/year)[(a)]	POTENTIALLY AVAILABLE (tons/year)[(a)]	ENERGY POTENTIAL[11] (kWelectric)
DAIRY MANURE	4,053,600	3,121,300	**28,000 kW**
	OTHER MANURES		
Beef Cows	276,000	27,600	230 kW
Hogs and Pigs	6,000	3,000	20 kW
Horses and Ponies	241,000	24,100	380 kW
Poultry	8,000	5,400	90 kW
Goats	3,000	300	10 kW
Sheep and Lambs	18,000	1,800	30 kW
			Subtotal = 760 kW
CHEESE WHEY	459,000	184,000	**990 kW**
	FOOD PROCESSING RESIDUALS		
Wastewater	310,000 gal/yr	310,000 gal/yr	1.5
Lagoon Sludge	100,000 - 400,000 gal/yr	100,000 to	0.5 to 2.1
Production Line Rejects	120 to 180	120 to 180	1.7 to 2.5
			Subtotal = 3.7 to 6.1 kW
	BREWERY RESIDUALS		
Spent Grains	2,000	0	0
Spent Yeast	133	0	0
Wastewater	9,300,000 to 18,600,000 gal/year	1,300,000 gal/yr	5
			Subtotal = 5 kW
FOOD WASTE	48,000	12,000	**220 kW**
Total			**29,760 kW**

(a): Except where noted.

[10]Ibid.

[11] For simplicity and for comparison purposes, the biogas produced from organic residues and wastes is assumed to generate electricity only, not electricity and some other form of energy.

POLICIES TO ENCOURAGE EMERGING RENEWABLE TECHNOLOGIES

GREEN PRICING

Green power is a term to describe electricity that is generated from renewable energy sources like the sun, wind, moving water, biomass, and the Earth's internal heat. Utility customers have requested electricity generated by green power, and utilities are responding by offering customers a mix of electricity from "green" sources. Since these technologies generally cost more than existing fossil-fuel generation, green power is sold at a premium price relative to the existing utility power mix. More than 50 green pricing programs are under way across the country. Most of Vermont's utilities are currently working on developing such program options for their customers. Central Vermont Public Service ("CVPS") has an approved tariff offering service from green sources. Green Mountain Power ("GMP") has proposed a tariff that would not only offer customers the option of purchasing green power, but also allow participating customers to receive stable energy prices offered by renewable energy sources. One way to look at green pricing programs is that they offer you a "vote" in what types of energy sources your utility will use to provide service to you. Your vote could result in new renewable energy facilities being built. After all, nationwide more than 110 MW of new renewables capacity have been installed to serve green power customers, with about another 105 MW planned.

On January 13, 2004, CVPS announced that the Blue Spruce Farm began producing electricity by burning waste methane gas for CVPS Cow Power™, a first-in-the nation program. More than 1,000 CVPS customers have signed up for CVPS Cow Power™ since the Vermont Public Service Board approved the concept in August, with dozens more enrolling each week. About half enrolled for 25 percent Cow Power, with the remainder evenly split between 50 percent and 100 percent.

Blue Spruce Farm is expected to produce about 1.7 million kWh of energy per year. Numerous other farms are considering the idea, some by combining their manure. According to CVPS, it takes a farm with about 500 milking cows to produce enough energy for the Cow Power concept to be economically viable.

The strength of green pricing is that it offers consumers the opportunity to register their vote for the types of energy sources the utility uses. There are, however, complicating issues associated with the details and design of green pricing programs that can challenge effective use of those programs to satisfy those preferences. Definitions of resources targeted and issues associated with the matching consumer participation to targeted resources can be challenging, and complicate program design and customer communications. The elements of program design therefore appear critical to achieving success.

RENEWABLE PORTFOLIO STANDARDS

The basic purpose of a Renewable Portfolio Standard is to support expanded development of renewable energy resources beyond what would have occurred without the program. A Renewable Portfolio Standard (RPS) is a set of requirements placed on entities that serve retail load, which require them to have their supply mix conform to a certain criteria as a condition of doing business in the state. Advantages of an RPS are that it can foster the development of a known quantity of renewable systems. Although electric suppliers must choose among a subset of technologies, suppliers of those technologies must compete to provide the best package to a load server. The burden of compliance falls on the utility. Regulators only insure compliance with stated standards. An example of how an RPS might work is, on an annual basis, any Load Serving Entity (LSE) might be required to acquire 4% of their supply from renewable sources. Compliance with an RPS is usually met by the use of renewable energy certificates (RECs). This would mean that if an electricity provider purchased 100 MWh of electricity, they would be required to retire four REC's to meet the requirements of the RPS. As discussed below, REC's can be purchased on the open market, or generated using owned facilities.

In New England, Massachusetts, and Connecticut have programs that are operating. New York has also adopted a RPS program. Each program has certain eligibility requirements for a generator to be a qualified renewable, which are dictated by the state. For example, both states only count energy produced by newly constructed renewable units as counting toward meeting the requirement.

Lawrence Berkeley Laboratory has published a set of design principles and best practices as applied to a renewable portfolio standard that was developed after review of existing state RPS programs. This set of guidelines which apply to RPS programs should offer guidance to Vermont policymakers should they choose to adopt an RPS.

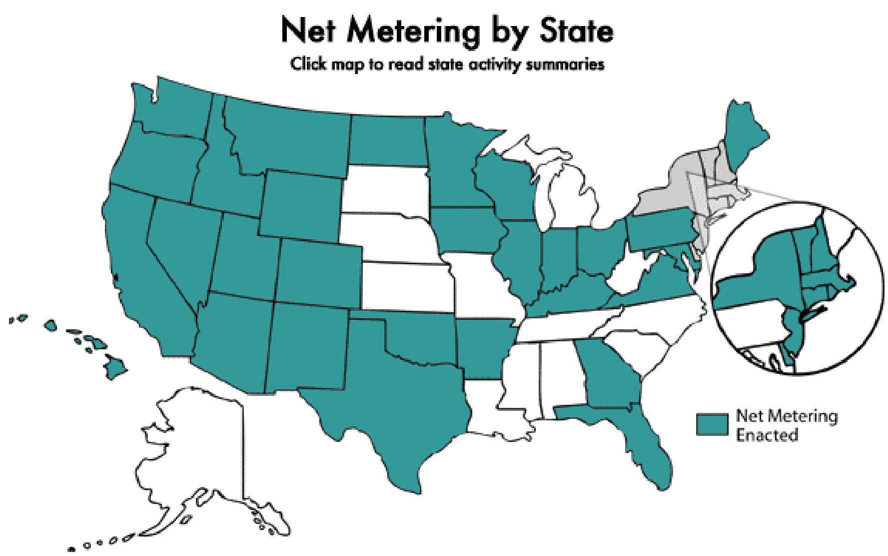
1. Social Benefit -- An RPS should be Socially Beneficial. The goal of an RPS is to foster the development of renewable technologies, with resulting decrease in environmental impact, decreased risk, increased resource diversity, and other ancillary benefits.
2. Flexible -- An RPS should be cost effective and flexible. A well-designed RPS is capable of being administered in a straightforward manner. Targets for renewable purchases should be achievable, given the supply demand balance. Uncertainty regarding this can be alleviated with the use of a price cap, should supply be unable to keep up with demand. The competitive procurement nature of the RPS should require a minimum of regulatory intervention.
3. Predictable and Sustainable -- An RPS should be predictable. The desire for long-term contracts needs to be bolstered with an assurance that the RPS requirements provide market stability for participants and generators. Without this predictability, suppliers will find it difficult to obtain financing for their projects.
4. Non-discrimination -- An RPS should be non discriminatory. Requirements should fall evenly on all customers and customer groups.
5. Enforceable -- An RPS should be enforceable with clear guidance regarding procedures in the case of non-compliance. If the RPS applies to all load serving entities equally, there is no competitive disadvantage to any entity.
6. Market Consistency -- The chosen RPS design should be consistent with the prevailing market structure. All load serving entities should participate on equal terms. Using tradable credits should not interfere with traditional energy procurement strategies.
7. Standardization -- A well-designed RPS should be compatible with other policies in the region and country. Vermont is not large enough to drive the market. Piggybacking on another state requirements for, say, eligibility requirements for generators could potentially reduce administrative work for a small state. RECs should remain fully bundled with all emission rights retained by the certificate. These benefits should not be transferred out of the REC program.

In both green pricing and RPS programs, the price for the REC's is market driven. That is, suppliers of renewable energy products purchase the renewable part of their offering on the open market through these certificates. The principal difference is that under an RPS program suppliers are mandated by law or regulation to obtain a certain level of renewable power supplies as a proportion of their supply mix. Green pricing programs are typically optional and their ultimate effectiveness depends on the level of demand generated by participating customers.

NET METERING

A Net metering program represents a simple, low-cost, easily administered method to encourage customers to invest in small-scale renewables. The essential feature of a net metering program is that the production from this system essentially runs the customer meter backward when the system produces more than the facility is using at any time. By using the interconnected utility as a sink for surplus production and source for additional power when needed, a net-metered customer can use the full monthly output of an installation to offset retail consumption. The broader implementation of net metering programs is seen as an essential step toward an increased penetration of small-scale renewable technologies into the market. Because net metering compensates customers that run the meter backwards at the fully loaded retail electric rate, a portion of which is above market and picked up by remaining electric customers, net metering presents some potential concerns for non-participants.

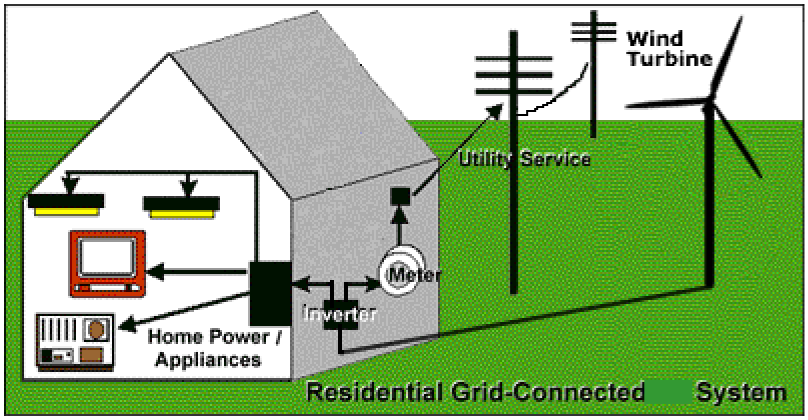
Figure 5-2 Net metering by state



Source: www.eere.energy.gov/greenpower/netmetering/#tx

Vermont's net metering statute became effective on April 22, 1998 and was amended in 1999 (H.705) and 2002 (S.138). In addition to allowing net metering for customers with PV, wind, fuel cell, and biomass gasification facilities of 15 kW or less, the statute establishes a new class of net metering system called the farm system. A farm system generates energy from the anaerobic digestion of agricultural waste produced by farming or other renewable system and can be up to 150 kW AC in generating capacity. The 2002 amendment also allows group net metering so a farmer can group their electric accounts together to use as an offset against the amount of electricity produced by on-site generation such as a farm based methane recovery system. Net metering customers that are farm systems may credit on-site generation against all meters designated to the farm system.

Figure 5-3 Residential Grid Connected System



Source: www.vermontwind.com/net_meter.html

Table 5-2 shows the permitted net metering capacity by system type. The total generating capacity under net metering for each electric company is limited to 1% of the company's peak demand during 1996. Excess generation during a billing period will be credited to the next billing period until the end of the calendar year. At the beginning of the next calendar year any remaining credits will revert back to the utility without compensation to the customer.

Table5-2

CPG INFORMATION FOR APPROVED NET METERING SYSTEMS

	TOTAL		Wind	Solar PV	Methane	Fuel Cell
TOTAL kW APPROVED	655	kW AC	278	312	65	0
NUMBER SYSTEMS	155	systems	39	116	1	0

There are currently 155 permitted net-metered systems, 142 of which have come online in the 2000-2003 period. During this period, the installed capacity of net-metered systems grew from 39.09 kW to 655 kW. Keeping with the trend of recent years, the majority of the growth occurred in residential applications, which account for 86% of all installed capacity, while commercial, school, farms, and non-profit applications account for the remaining 14%.

The legislature passed a sales tax exemption on equipment used in net-metered systems. In 2002 the exemption was expanded to cover solar hot water systems and off-grid renewable energy systems that meet a number of the previously established specifications for net metering equipment.

A PV system for net metering must conform to safety, power quality, and interconnection requirements established by the National Electrical Code and the Institute of Electrical and Electronics Engineers. For the full text of Vermont's net metering statute, see 30 V.S.A. §219a.

TAX CREDITS AND INCENTIVE PROGRAMS

Fiscal inducements are a common tool for advancing policy. For example tax credits have been widely used in the advancing of energy policy.

Vermont's Solar and Small Wind Incentive Program was established pursuant to Renewable Energy Legislation passed by the Vermont State Legislature during the spring of 2003, and signed into law by Governor James Douglas on June 17, 2003. The program utilized Petroleum Violation Escrow funds and a portion of an insurance refund received by the utilities when the sold the Vermont Yankee nuclear plant to provide incentives for qualifying solar electric, solar hot water, and small wind systems. As established by the DPS $581,000 was available for the solar and small wind incentives. The Renewable Energy Resource Center (RERC), a project of the Vermont Energy Investment Corporation (VEIC), administers the incentive program and provides consumer education and support services.

The overarching goal of the program was to accelerate and increase market demand for high quality solar and small wind systems. The program incentives covered approximately 35% of the total installed cost for eligible systems and are expected to leverage approximately $1.5 million in private investment. Total energy savings are estimated to be roughly 10,000 gallons/year of fuel oil (from off-set hot water heating), and 325 MWh of electricity (combined total for wind and solar electric systems).

RENEWABLE ENERGY FUNDING

Renewable energy funds are also a mechanism for promoting the development of clean technologies for utility-scale projects. They have the advantage of being relatively flexible in targeting the technologies and projects. While renewable energy or clean energy funds have typically focused support on the deployment and commercialization efforts, funds are also used to support earlier stages of technology development. A significant number of states now have funds. Fourteen states have established clean energy funds in the US. 17 Funds in 12 states are now part of the Clean Air States Alliance with offices based in Montpelier, Vermont.[12]

Vermont created a relatively small fund that resulted from the Nuclear Electric Insurance Limited (NEIL) refunds of 2003 and 2004. Pursuant to Public Service Board Order in Docket 6546, Green Mountain Power and CVPS were asked to prepare plans for expenditure of the refunds. In total, approximately $1.345 million was available to GMP and CVPS. Plans for the fund included a 30% share targeting the Vermont Small Wind & Solar Fund. Funds were also used to create a CVPS Renewable Development Trust Fund, develop GMP's Essex Hydro Bypass Turbine, and GMP's Voluntary Renewable Pricing Program. Future "excess funds from Vermont Yankee" are to be used in a similar fashion pursuant to plans filed with the Board.

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[12] Mark Bolinger, Ryan Wiser, Garrett Fitzgerald, *The Impact of State Clean Energy Support for Utility-Scale Renewable Energy Projects, Berkeley Lab and Clean Energy States Alliance, October 2004.*

RENEWABLE CREDITS AND TRADABLE ALLOWANCES

RECs are tradable certific ates that represent the environmental attributes of electricity generated from renewable technologies. When electricity is generated by a renewable facility, its commodity can be unbundled from the green attributes of that electricity. Those attributed are known as RECs. The electricity generated is split into two distinct quantities – one is the commodity electricity which is like any other electricity entering the distribution system and the other is the attributes, or green tags, from that generation.

Marketers of clean power acquire these RECs on the market to validate their product claims. Sellers of electricity, in states where there is a requirement to meet some demand with renewable generation purchases these RECs to meet those requirements. From a developer's point of view, selling RECs helps bring additional revenues back to the owners of those installations and encourages further development of renewable installations and technologies.

DISTRIBUTED RESOURCE TECHNOLOGIES

Distributed resources are generation assets that are placed at lower voltage locations on the grid or in congested areas of the grid. Injecting energy in these locations can offset line losses and, in some cases, can provide an alternative to transmission upgrades. Distributed resource technologies should have the following characteristics: First, since they interconnect on smaller lines, they should be scalable so as not to exceed the capacities of distribution facilities and substations. Capacities of most distribution feeders are in the range of five MW to ten MW. While actual limitations depend on a number of factors including the distributed resource's specific location, the network configuration, and existing loads, generating units greater than several MW in capacity are generally not suitable as distributed resources. Second, distributed resource technologies should be modular and easily deployable. As distributed generation technologies mature, it is hoped they will be more like household appliances in their application. In the same way an electric dryer needs a 220-volt plug and an air vent, the goal of modular DG technologies is to hook into a fuel source, plug and an air vent. This modularity will greatly simplify the installation process for these technologies. This modularity and scalability will also allow planners to better match the output characteristics of the units to the local demand, thereby gaining the most from each installation.

At present, the U.S. and Canadian firms buy about 3,400 MW of small generators each year. While most of this generation provides backup power, some of it provides the primary electric source for selected loads and facilities. Forecasters predict substantial growth in the distributed generation market in the coming years. The Electric Power Research Institute (EPRI) estimates a potential distributed generation market of 2,500 MW per year in the U.S. by the year 2010. The U.S. Department of Energy estimates that by the year 2010, distributed generation will account for as much as 20% of all new domestic power generation capacity additions.

Fuel Cells

Rather than the typical combustion process that is used to generate steam and then electricity through the use of a steam turbine, fuel cells convert the fuel directly into electricity through the use of a chemical process. Fuel cells are more efficient that conventional power generation systems because of the nature of the power production process. Electrical efficiency of fuel cells is about 40 to 60 %. When the excess heat of the fuel cell is used for process equipment for example, a gain of efficiency ranging near 20% is normal. Another advantage to fuel cells is that they generate lower levels of pollutants than other generation sources.

Although alternative fueled fuel cells are currently under development, hydrogen is most often selected as the fuel source. Some fuel cells extract hydrogen from natural gas. This process is somewhat less efficient than using hydrogen as the fuel source but is arguably more practical because of the existence of natural gas pipeline distribution systems.

Fuel cells at this point are a developing technology with a growing number of prototype installations in place. There has been much discussion about the use of fuel cells in vehicles. One advantage of the technology is that at night the electricity produced by the fuel cells could be used to power homes and neighborhoods.

At this point there are many schools of thought as to the best course of action regarding fuel cells. Hydrogen distribution systems are not yet in place and there is much controversy over the costs and practicality of overcoming the hurdles necessary to install a hydrogen distribution system. Vermont should keep a close watch on this technology though as it shows much promise as source for clean reliable, relatively environmentally friendly power.

Micro-turbines

Micro-turbines are small modular gas turbines, with one moving part, ranging in size from 30 kW to several hundred kW. Like fuel cells, micro-turbines operate on a variety of fuels including gasoline, diesel, and natural gas. Micro-turbines are quiet, operate at high speeds, and employ rectifiers and static power converters to convert high-frequency AC to DC and then to 60 Hertz AC. Their modular design greatly reduces the engineering and installation costs for a typical installation. Some models can also be operated in a cogeneration mode, supplying hot water to a facility as well as electricity. Like larger gas turbines, micro-turbines are readily dispatched and well suited for commercial and industrial applications. First generation micro-turbines yield relatively low efficiencies of about 30%, but also have moderate capital costs of around $600/kW. It is anticipated that micro-turbines that are fueled by natural gas, without cogeneration, will produce electricity for 7 cents to 10 cents per kWh, making them competitive with utility service in the near term.

Photovoltaics (PV)

PV panels are made of semiconductor devices that convert sunlight into DC electricity. Static power converters are used to convert the DC into usable 60 Hertz AC. PV panels are modular, lightweight, contain no moving parts (unless tracking devices are used), release no emissions, need no water, and have low operation and maintenance requirements. They can be placed on rooftops giving this technology significant siting flexibility. Compared to other distributed technologies, they remain relatively costly at about $5,000/kW installed. PV technology also requires relatively large areas to produce significant amounts of power. The most common applications of this technology to date have been to power small loads in remote, off-grid sites where utility line extension costs are prohibitive. As they become more widely used, it is anticipated that resulting mass production will lead to significant price decreases.

Combined Heat and Power systems (CHP)

Combined heat and power systems extract additional energy from a primary generation fuel by capturing the heat, which is wasted during the generation cycle and converted it into useful energy, generally in the form of heat. This heat can be used for space heating applications, or in the case of industrial CHP systems, for process heating needs. Process heating needs – this heating needs which are present year around, offer the most economically attractive applications of CHP because the equipment can have a higher utilization rate. However, in Vermont, where heating is a six month or more proposition, CHP for space heating has merits as well. Because these CHP systems are located "within the fence" they offer the advantages of distributed generation as well.

The University of Vermont (UVM) has been evaluating a possible co-generation plant in recent years. This project could present many of the positive attributes of cogeneration by providing affordable electricity, being close-to-load, capture of waste heat. UVM is in the process of expanding campus facilities and view the prospect of co-generation as a means to serve incremental load and even a more efficient way to cool buildings during the summer session.

Others

A number of other technologies exist that are appropriate for distributed utility plan applications. The most established distributed technology is the reciprocating engine/generator set. These engines run on a variety of fuels, come in sizes from five kW to tens of MWs, and have installed costs ranging from $500/kW to $1,500/kW. These sets are mass-produced, are supported by established sales and maintenance infrastructures, and are now available as residential and commercial cogeneration packages. The drawbacks to this technology include relatively high emissions, high noise, and frequent maintenance.

One of the fastest growing distributed technologies is that of wind turbines. Recent technological advances have increased the efficiency and reliability of wind turbines while lowering their costs. Installed costs range from $1,000/kW to $3,000/kW. While wind turbines have no fuel requirements and zero emissions, there are potential noise and visual aesthetic concerns, depending on the specific application. Another class of distributed technology is the energy storage system, with the most common energy storage device being the battery. Batteries store energy in chemical form and like other storage devices can be used for peak shaving, spinning reserve, outage support, and voltage and transient stability. While not yet viable for storing large amounts of energy, batteries are currently used for uninterruptible power supplies, support for off-grid PV and wind systems, and emergency backup for lighting and controls.

RECOMMENDATIONS

RENEWABLES

- Vermont regulators should establish proceedings for adopting appropriate recommendations of the Advisory Commission on Commercial Wind Energy.
- The Departments and State agencies should support the next-stage of developments resulting from the investigation of the Advisory Commission on Commercial Wind Energy into permitting issues. Recommendations identified Act 248 review as the appropriate vehicle for reviewing commercial wind generation projects, 10-mile radius notification, notifications requirements to municipalities and planning commissions, and a decommissioning fund for site restoration. The recommendations also include the use of an ombudsman contact for the Section 248 review process.
- Vermont should continue to encourage and promote development of net-metered renewable energy applications in appropriate locations.

- Vermont should promote the use of PV systems in those markets where they can be cost effective substitutes for line extensions or temporary installations.
- Vermont utilities should evaluate, develop, and implement well-designed and properly focused voluntary green-pricing programs.
- The DPS and State government should evaluate financial incentive mechanisms to foster renewable energy deployment.
- Electric utilities should explore potential for appropriate new renewable resource acquisitions as existing energy sources and contracts expire.
- Vermont utilities should work with merchant generators and developers of renewable energy projects to encourage and overcome artificial barriers to the development of cost-effective viable renewable energy projects.
- State regulators and utilities should monitor renewable technology improvements and assess cost-effectiveness and applicability for Vermont. Their federal legislative delegation should be encouraged to seek additional funds for advanced technology to support renewable energy development in the state.
- State regulators should encourage utilities and independent power producers to investigate the feasibility of retrofitting existing wood burning generators with fluidized bed systems to improve the emissions characteristics.
- Utilities and the DPS should evaluate incentives and viable means to enhance deployment of co-generation systems.

CHAPTER 6: Demand Side Management, Energy Efficiency, and Conservation

INTRODUCTION

Traditionally, in response to increasing demand for electric energy, utilities built new power plants and infrastructure to ensure their customers a reliable and stable source of power. As costs to build new plants continued to rise, the search for more cost–effective power options became more important. Rather than always choosing to build to meet the increasing demand for power, stakeholders, including regulatory agencies, contemplated addressing the problem on the customer side of the meter—where the demand is created. If the demand for power could be lowered through energy efficiency and load management, the costs to build new power plants and pole and wire upgrades might be deferred. The expected end result would be lower utility costs over the long term for customers. Stakeholders decided the costs associated with reducing electric use and the benefits produced should be fairly compared to the costs and benefits of the traditional build-up approach. The concept of acquiring energy efficiency resources through demand side management was born.

Demand side management resource strategies aimed at increasing energy efficiency on the customer side of the electric meter generally fall under the following categories:

- Energy efficiency—selecting equipment that will perform the same work with less energy input.
- Load response—customers agree to respond to utility requests to reduce use during times of utility peak demand.
- Load management—encouraging customers to reduce their loads during peak times of day and peak season through the use of time-of-use rates, seasonal rates, and interruptible contracts; or direct load control where a utility interrupts power supply to customer equipment.

Since 1990, Demand-Side Management (DSM) programs in Vermont have contributed more than 400,000 MWh in cumulative electricity savings, and reduced Vermont's Cumulative Winter Peak by more than 90 MW. (See Figure 6-1.)

Today Vermont's electric energy efficiency programs are administered by a statewide entity funded through an Energy Efficiency Charge (EEC) on all customers' bills. Efficiency Vermont, which currently serves as the state's energy efficiency utility, delivers a set of statewide energy efficiency programs to most customers in the state.[1] Electric distribution utilities remain responsible for other demand side management, including DUP DSM, load response programs, and load management strategies.

[1] Burlington Electric Department (BED) implements comparable energy efficiency programs in its service territory.

The term "energy conservation" is sometimes used instead of "energy efficiency" when talking about saving energy. For the purposes of this document, energy conservation means using less energy through changes in behavior such as turning off lights, turning down thermostats, hanging clothes on the line instead of using a clothes dryer. Energy conservation is sometime equated with reductions in energy service. This contrasts with "energy efficiency" which is generally associated with the concept of an equivalent level or increased level of service while using less electricity. Energy conservation is not generally relied upon by utilities as a demand side management strategy, but it can be a valuable way for users of electricity to reduce their own electric energy costs and make a contribution to reducing environmental impacts. It also plays an important role in maintaining reliability when periods of unusually high peak usage threaten to overwhelm the system.

Figure 6-1

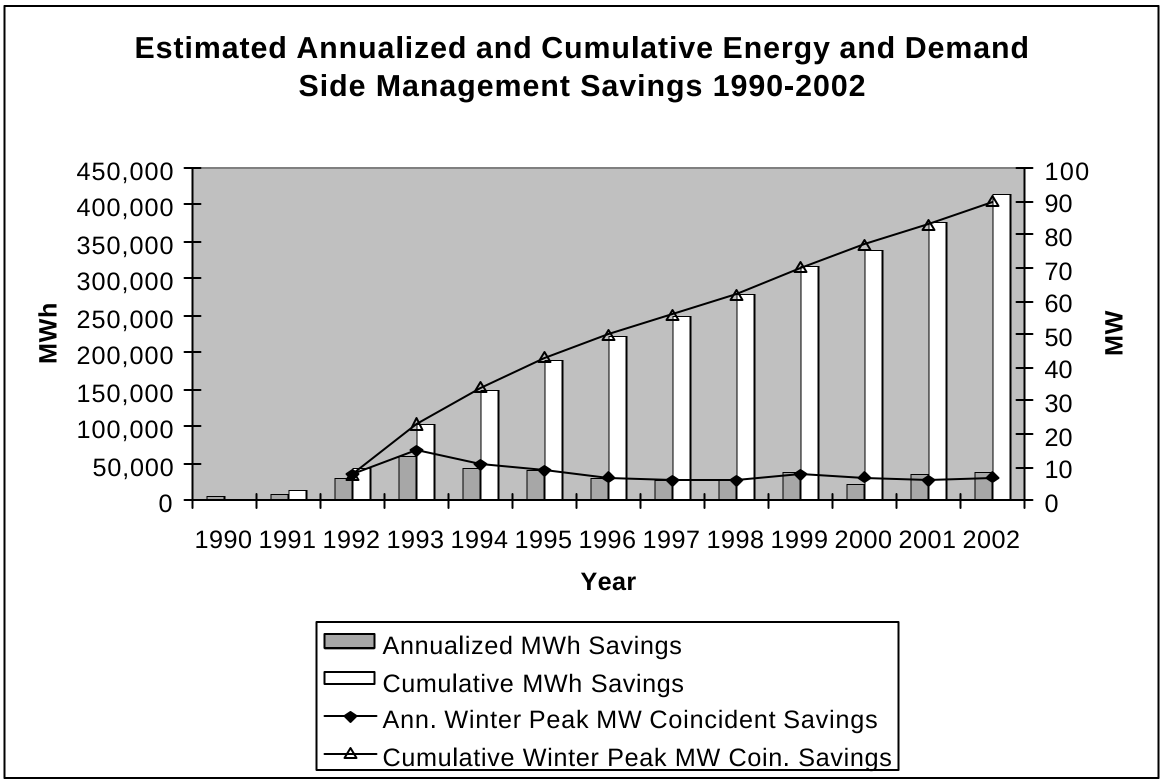

Table 6-1 Annualized Incremental MWh Savings

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Burlington Elec. Dept.	5,219	7,268	5,291	9,623	4,502	6,764	2,285	2,663	3,202	1,303	2,767	2,702	3,789
Central Vt. Public Serv. Corp.		2,469	12,112	26,467	19,182	19,876	12,846	11,613	11,689	17,059	2,250		
Citizens Utilities			1,992	3,918	5,052	3,629	2,396	2,029	3,286	5,011	2,211	551	119
Green Mountain Power		79	9,698	18,514	14,433	9,198	10,399	8,328	8,287	9,396	445		
Washington Electric Coop.			360	726	1,102	1,134	889	674	489	445	215	200	
Vermont Electric Coop.						0	608	1,285	1,666	2,503	550	374	265
VPPSA Member Systems				593	1,681	926	957	1,745	710	1,801	210	177	
Vermont Marble Power Division				406				>2	2.7	12	30		
Rochester Light & Power Co.										35	0		
Efficiency Vermont (EVT)											20,081	32,041	34,648
Total MWh Savings	5,219	9,816	30,350	59,417	44,765	41,528	30,380	28,337	29,329	37,565	28,760	36,045	38,821
Percent of Total Electric Consumption	0.10%	0.18%	0.55%	1.06%	0.79%	0.70%	0.50%	0.47%	0.53%	0.65%	0.48%	0.61%	0.65%
Cumulative Percent of Electric Consumption		0.3%	0.8%	1.9%	2.7%	3.4%	3.9%	4.4%	4.9%	5.5%	6.0%	6.6%	7.3%

Note: Savings reported as - At Customer Meter, net free riders and spillover. Source: DPS

A BRIEF HISTORY

Before the oil crisis of 1973, the focus of the American electric utility industry was growth. The industry's operating assumption was that the more electricity its customers used, the less that electricity would cost. Vermont was not an exception to this way of thinking and electricity use in the state soared in the decade prior to the oil crisis. Sales grew by more than 10% a year during this period, which was much faster than the rate of population growth. Sales to commercial and industrial customers grew two-and-a-half times as fast as employment. It was not until OPEC's 1973 oil embargo that the U.S. started to consider other resources for their power. As energy prices escalated through the early and mid-1970s at double-digit annual rates, energy conservation and energy security quickly became a national concern.

Reacting to the new public sentiment that energy conservation was a patriotic duty, many Vermont electric utilities began providing information about reducing energy use to their customers. Early state and federal energy legislation also had an indirect effect on electricity use by providing tax credits for energy conservation measures, grants to institutions that installed energy conservation equipment, and home energy audit programs. To reflect the high cost of peak power, in 1974 the Public Service Board (PSB) ordered Central Vermont Public Service (CVPS) to begin charging customers higher rates for power during the cold weather peak season. As part of this change in the rate structure, large electric customers were charged "time-of-use" rates that offered lower cost power during off-peak periods and charged a premium for on-peak consumption.

As a result of the new rate designs and load control programs, along with other household trends, there was a partial flattening out of Vermont's seasonal electricity use and a slower growth rate in statewide electric sales after 1973. This kept the increases in average electricity rates roughly in line with the rate of inflation. Moreover, utilities at least partially sidestepped the need for billions of dollars of investments in new generation plants.

By 1981, several Vermont utilities were involved in limited energy efficiency and energy conservation efforts. Most promoted energy saving devices as they came on the market such as foam gaskets to stop cold air leaks at electric outlets, wooden wedges meant to jam double hung windows tight, weather-stripping to seal doorways, insulating jackets for water heaters, and flow restrictors to reduce the use of hot water. In focusing on these simplistic measures, the utilities missed the opportunity to provide customers with a comprehensive energy efficiency strategy that would have saved far more electricity. They also ignored the opportunity to change energy design and construction practices for new buildings. By thinking of energy conservation as merely a service that motivates customers, the utilities missed the opportunity to free up enough electricity from existing sources to meet much of the state's current and future power needs.

There were some positive results from these early conservation efforts. The utility promotions of water heater jackets, for example, demonstrated the potential for energy savings with this device. The utilities' experience with water heater controls demonstrated that water heating load management programs made economic sense and programs were implemented for utilities to control customer water heating loads from the utility control room.

Additionally, government weatherization programs demonstrated the vast potential for efficiency improvements in the existing building stock. With federal funding assistance, Home Energy Audit Team (HEAT) provided energy audits and information about weatherization and other energy saving techniques to 22,000 homes between 1978 and 1985. Vermont's Weatherization Assistance Program helped low-income households lower energy consumption by an average 20%. In 1980,Vermont Industrial Energy Conservation Advisory Program (VIECAP) began providing on-site energy evaluations for businesses and by 1993 they had provided energy evaluations for 53% of Vermont industries. The Residential Conservation Service (RCS) programs mandated by the federal government and funded by utilities also reached hundreds of customers with energy saving services.

THE FIRST TWENTY YEAR ELECTRIC PLAN

By 1983, when the Department of Public Service (DPS) published its first *Vermont Twenty Year Electric Plan*, conservation experience in Vermont and elsewhere had convinced them that there was far more potential for improving the efficiency of electric power use than utilities were tapping. They estimated that Vermont's peak electricity demand could be reduced up to 13% by the year 2000 if efficiency programs that had already shown themselves to be effective were implemented on a larger scale.

Accordingly, the 1983 Plan proposed that each utility "devise and implement a comprehensive conservation plan" at least as effective and economical as the three programs on which the DPS had based its estimates for potential demand reduction. This flexible language was meant to encourage further innovation and to allow each utility to determine what efficiency programs would be most cost-effective in its particular economic circumstances. From this information, the utilities were expected to determine when conservation would make more economic sense than acquiring additional generation sources.

As a fallback, the Plan presented a minimum approach to conservation that a utility could adopt. In addition to increasing the efficiency of its own transmission and distribution systems, a utility could implement the following three basic customer efficiency programs:

- A "wrap-up" program for improving the efficiency of at least half of the electric water heaters within five years;
- A "seal-up" program for reducing household heat loss in at least half of the electrically heated homes within five years; and
- A load management program to make two-thirds of the electric water heaters subject to load control within ten years.

EARLY UTILITY EFFICIENCY PROGRAMS

The early energy efficiency programs had limited success. Following the demise of the HEAT and RCS programs in 1985, about 50% of CVPS customers had purchased water heater jackets, but few implemented additional conservation measures. The first of CVPS' "Money Bags" programs, which offered a discount on weatherization supplies, sold only 148 packages among the utility's 110,000 customers. In 14 months of operation, a revised "Money Bags II" program that used private contractors reached only 42 customers. Between 1985 and 1988, the SEAL-UP program provided 1,400 do-it-yourself home energy audits, reaching a larger but still tiny share of the market. The component of the SEAL-UP program that arranged low interest loans to help low income customers make conservation improvements processed only 49 applications in this four-year period, half of which were then rejected by the banks involved.

Green Mountain Power’s (GMP) SEAL-UP program provided household energy audits and offered four-year loans to buy energy saving equipment, but only 1% of GMP's eligible customers actually implemented the efficiency measures the auditors recommended. Vermont Public Power Supply Authority (VPPSA), a consortium of smaller publicly owned utilities, agreed to study water heater switch off devices for its member utilities, but the study was abandoned in 1985. By 1988, only three VPPSA member utilities had water heater wrap-up programs, and combined they had only installed 13 water heater jackets.

Successes in the early utility efficiency programs were achieved mainly in areas where the utilities were already skilled-engineering and rate design. For example, by 1986, CVPS had installed timing or ripple devices on 50% of its customers' electric water heaters. GMP had fitted 6,000 water heaters for ripple control, reaching 30% of eligible customers by 1987. Post-oil-crisis utility rates and billings provided customers with an incentive to reduce power use during peak periods. Before these rates took effect, Vermont's peak load was growing faster than overall power use. Afterward, peak load grew more slowly than overall power use.

Although utilities achieved some successes with their early efficiency programs, the potential the Plan envisioned was not realized. Achieving those savings would have required a more in-depth and comprehensive approach to reducing the energy use of large numbers of customers. To achieve the projected energy savings, efficiency measures that could permanently reduce the electricity required to run appliances were needed, and thousands of customers had to be convinced to take these steps. Because the 1983 Plan's three basic programs were adopted with minimum changes to a utility's established priorities, and were implemented using the traditional methods and procedures of utility departments, they had very little impact.

THE SECOND TWENTY-YEAR ELECTRIC PLAN

In 1988, the DPS issued the second edition of the Plan reflecting what had been learned about energy efficiency programs since 1983. At around the same time, the Public Service Board (PSB), which regulates utility rates and power investments, began a two year investigation of energy efficiency programs to determine if any regulatory steps should be taken to maximize Vermont's potential for efficiency savings. Both the 1988 edition of the Plan and the PSB's 1990 Order in Docket 5270 came to similar conclusions:

1. Efficiency improvements could meet a significant portion of Vermont's current and future electric needs with less risk and less financial and societal cost than by generating power or building new power plants.
2. The potential to meet future needs through efficiency improvements would remain untapped until the state's electric utilities started treating efficiency measures as seriously as traditional supply options when planning an integrated least cost strategy for meeting electricity needs.
3. Current energy efficiency programs were inadequate. Customers needed to be provided with accurate price signals about the real costs of inefficiency and persuasive information about the benefits of implementing efficiency measures. Most customers would not spend money on efficiency measures unless the payoff to them was prompt and the inconvenience minimal.
4. Prescribing specific, limited energy efficiency programs for utilities to adopt had been inadequate. Vermont had to encourage comprehensive and cost-effective energy efficiency measures for new and existing buildings.

DEMAND SIDE MANAGEMENT MANDATE

Many of the principles in the Docket 5270 order were also endorsed by the Legislature and incorporated into the 1990 Act No. 273 (amending 30 V.S.A. §248). Act 273 stated that approval of any utility proposal for a new source of electric power must be contingent upon the demonstration that this would be more cost-effective than meeting the same needs through increasing efficiency. In 1991, Act No. 99 added 30 V.S.A. §218c that required least cost integrated planning by all electric and gas utilities.

Both the Legislature and regulators were directing Vermont utilities to undertake least cost integrated planning and to prepare integrated resource plans (IRPs). The IRPs forecast customers' demand for energy over a 20-year period and analyzed the optimal portfolio of resources to meet this demand at the lowest societal cost. This preferred portfolio would include the lowest-cost options selected from existing and planned generation sources as well as investments in comprehensive energy efficiency programs.

The second new concept resulting from this legislation was DSM, defined in the 1988 *Plan* as "a systematic, integrated pricing, engineering, and marketing approach to optimize the efficiency of electricity use." DSM resources were targeted in all customer classes (residential, agricultural, commercial, industrial) and addressed new construction and renovation, equipment replacement, and retrofit of existing customer premises.

FORMATION OF THE "ENERGY EFFICIENCY UTILITY"

On June 1, 1999, S.137 became law, amending Sections 209 and 218c of Title 30. The new law confirmed the PSB's authority to appoint "one or more entities" to deliver energy efficiency services in the state and set overall funding levels and rate design requirements. On September 30, 1999 the Vermont PSB, through Docket No. 5980, approved the creation of an Energy Efficiency Utility (EEU) to deliver efficiency services to residential, commercial, dairy, and industrial electric customers throughout Vermont, beginning early in the year 2000. The PSB's order approved a Memorandum of Understanding (MOU), which contained a transition plan and described items such as transition expenses, rate recovery for current DSM expenditures, responsibilities in the collaborative process, limits to system benefit charges, and ACE[2] recovery. The MOU was the result of two years of work and collaboration by the DPS, the state's utilities, and several stakeholder groups.

In March of 2000, Vermont became the first state in the nation to have its energy efficiency programs administered by a statewide entity funded through an Energy Efficiency Charge ("EEC") on all electric utility customers' bills.[3] Efficiency Vermont (EVT) serves as the state's Energy Efficiency Utility under contract with the PSB. The initial contract for services for calendar years 2000-2002 was renewed for a second 3-year period to provide services for 2003-2005. The initial contract included programs detailed in the Vermont DPS Energy Efficiency Plan, Docket No. 5854, *The Power to Save: A Plan to Transform Vermont's Energy-Efficiency Markets*. EVT delivered seven statewide core energy efficiency programs as part of its initial three-year contract. These programs were: Residential New Construction, Efficient Products, Residential Low Income Single-Family, Residential Low Income Multi-Family, Farm Retrofit, Commercial Energy Opportunities serving both new construction and equipment replacement/renovation/remodeling markets) and Customer Credit. For the three-year contract renewal period (2003 – 2005), the markets are the same as under the initial contract. However, EVT proposed and the PSB approved certain reconfigurations and renaming of their services to the markets identified in *The Power to Save*.

Electric utilities remain responsible for demand side management activities related to transmission and distribution constraints through Distributed Utility Planning (DUP), discussed below in this chapter and in Chapter 8.

STRUCTURE OF THE ENERGY EFFICIENCY UTILITY (EEU)

Organization

The efficiency utility operates under a contract awarded after a competitive solicitation by the PSB. The entity selected to perform the duties of the EEU contracts with and reports directly to the PSB. The contract extends for three years, with a three-year renewable clause. Every six years, the PSB must issue a new competitive solicitation to select an entity to serve at the EEU.

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[2] Account Correcting for Efficiency.

[3] BED received PSB approval to implement the core programs in its service territory with the same "look and feel" as EVT's programs. WEC also obtained PSB approval to continue some of its own DSM efforts and to pay a lower EEC amount for the first three years of EEU operation.

There are no specific restrictions on corporate form for entities serving as the EEU.[4] The EEU can be a non-profit organization, a private corporation, an energy-service company, or a consortium of firms or organizations. The entity can already be in existence, or be explicitly established for the sole purpose of serving as the EEU. The contracting entity needs to have demonstrated competencies in the areas of responsibility to be assumed. It also needs to be structured to be free of conflicts of interest.

Funding

Program costs for the EEU are funded through the use of a non-bypassable, volumetric system benefits charge, known as an EEC that appears separately stated on Distribution Utility (DU) customers electric bills. For the first three years, the EEC was set separately for each distribution utility and, to the extent possible, the DU rates were lowered to offset the amount to be collected through the EEC. In 2003, the rate design of the EEC was changed so that the charge is the same, regardless of utility service territory, for most residential, commercial, and industrial customers in the state.[5] The PSB recently initiated a rulemaking to simplify the annual setting of the charge. The EEC is collected by utilities, and forwarded to a Fiscal Agent who disseminates the funds to the EEU and other entities funded by the EEC.

In its May 29, 2002 *Report and Recommendations to the Vermont Public Service Board Relating to Vermont's Energy Efficiency*, the DPS recommended the PSB renew its contract with Efficiency Vermont (EVT) for another three years and recommended total annual funding levels for the contract period.[6] On August 1, 2002 the PSB renewed its contract with Efficiency Vermont for an additional three years and set the total EEU funding levels recommended by the DPS. On October 31, 2002, the DPS modified its recommendation for the year 2003 and proposed to reduce the initial funding level of $16.2 million to $14.0 million. The revised funding level was approved by the PSB in a split decision. The current funding levels are as follows:

Table 6-2 EEU Funding Levels 2003-2005

2003	**$14,000,000**
2004	$16,321,795
2005	$17,500,000

Oversight and Regulation

The EEU fulfills its contractual obligations with a degree of autonomy similar to that previously enjoyed by utilities in their operation of DSM programs. It submits to oversight and regulation by the DPS and PSB, respectively. The EEU submits regular reports to the DPS, the PSB, and the legislature. The Efficiency Utility is answerable to distribution utilities only to the extent that it provides contracted delivery services for them as part of targeted utility DSM programs. The PSB designates a Contract Administrator to handle the day-to-day management of the contract between

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[4] However, the entity serving as the EEU may not sell electricity to Vermont retail consumers during the term of the contract or for one year thereafter.

[5] The EEC for BED customers is calculated separately, as BED delivers the statewide programs in its service territory. Also, WEC customers currently pay a slightly different amount, per a PSB-approved agreement with the DPS. Starting in the year 2006, WEC customers will pay the statewide EEC.

[6] The total EEU budget includes funds for EVT and BED core programs, plus funding for the DPS EVT evaluation activities, the PSB's Contract Administrator, and the PSB's Fiscal Agent who receives and disburses the EEC funds.

itself and the EEU. The Contract Administrator interprets the contract terms, administers reporting requirements, receives and resolves complaints or disputes, and advises the PSB of its determination of the EEU's performance as set forth in the contract. The Fiscal Agent fulfills an accounting function, taking monies collected by distribution utilities, making sure the correct amounts are collected, and dispersing those funds to the EEU and to any other entities funded by the EEC.

Operation

The EEU's primary responsibility is to administer all statewide energy efficiency programs. This broad set of responsibilities includes program marketing, delivery, and tracking and monitoring. It also includes a variety of coordinating and reporting functions. The Efficiency Utility's program marketing responsibilities may include:

- Direct customer marketing;
- Direct marketing and interface with trade allies;
- General communication on energy efficiency programs; and
- Brand and service mark development.

Program delivery services may consist of:

- Participant intake and processing;
- Provision of specialized efficiency expertise and information;
- Delivery contractor training;
- Contractor management;
- Contractor arranging services for customers;
- Processing of customer efficiency incentives;
- Specialized technical assistance for individual participants, such as diagnosis and specification;
- Inspections;
- Scheduling;
- Quality control;
- Commissioning; and
- Bulk buying of equipment or materials (lighting for direct installation).

The Efficiency Utility must collect, manage, and analyze a wide variety of information during the course of program operation. These tracking and monitoring functions include:

- Tracking data on participating customers, trade allies, and general program operation;
- Regular reporting to the DPS, PSB, utilities, and the legislature;
- Coordinating data collection with other entities, including utilities, retail energy service providers, and the DPS;
- Making ongoing adjustments to program operation based on tracking and monitoring; and
- Providing savings information to distribution utilities for their planning purposes.

Acting in concert with the DPS, the EEU is primarily responsible for coordinating programs with regional and national efficiency efforts. For example, the efficiency utility must maintain consistency with regional efforts at market transformation, such as those sponsored by the Northeast Energy Efficiency Partnership (NEEP). It is also the Efficiency Utility's responsibility to coordinate the acquisition of relevant customer information from distribution utilities. They also coordinate the use and sharing of that information in an appropriate way between itself and its subcontractors, the DPS, distribution utilities, and retail energy providers.

The Efficiency Utility also provides a major supporting role in several other areas including DSM resource planning, program evaluation, and coordination with energy efficiency codes and standards. It also plays a significant role in arranging and implementing energy efficiency financing mechanisms with non-utility financing sources.

Burlington Electric Department Core Services in Service Territory

BED implements most of the core programs in its service territory and is subject to the DPS review and the PSB approval of their programs. BED remains subject to the provisions of Docket No. 5270, and to the traditional principles of regulation, with respect to implementation of programs other than core programs. It is also subject to the same performance standards as is the EEU, with respect to its core programs, as well as to traditional regulatory review of any expenditure it makes in implementing those programs.

Efficiency Utility Performance Contract

Efficiency Vermont provides statewide energy efficiency services under a performance contract with the Public Service Board. Under the EVT contract, the PSB authorized the contractor to receive payments for meeting certain performance measures. A portion of the payment is based upon the contractor's successful delivery of the core energy efficiency programs. The contractor can receive additional payments by meeting specific program performance indicators. The minimum performance indicators for the current contract are:

- Electric benefits alone, before examining societal benefits, must meet or exceed program costs.
- Threshold (or minimum acceptable) level of participation by low-income households; 15% of all spending to be for low-income single and multi-family services.
- Threshold (or minimum acceptable) level of participation by non-residential customers: 40% of total non-residential accounts with savings are accounts with annual electric use of 40,000 kWh/yr or less.

The performance award indicators are summarized below:

- Cross-sector—annual incremental net MWh savings, committed projects MWh, summer peak kW.
- Total resource benefit (TRB) -- present worth of lifetime electric, fossil fuel, and water savings.
- Residential sector—double market share of new five star Energy Rated Homes.
- Business sector—Comprehensive New Construction—annually increase the percentage of new construction, addition, and renovation projects that participate in the comprehensive track (either enhanced or simple); Business market—cumulative HVAC net MWh savings.
- Geographic Equity—Minimum TRB to county contribution ratio.

Under its performance contract, EVT must also obtain a specified amount of cost effective electric savings and total resource benefits from programs and services offered throughout Vermont and to assure that such activities and results provide geographic and customer class equity over time.[7]

[7] 30 V.S.A. § 209 (e)

The PSB must conduct a new competitive solicitation in 2005 for an entity to serve as the EEU at the completion of the current contract ending in 2005.

EEU COSTS AND BENEFITS

EVT's total expenditures during the first three-year contract were $25.4 million, which resulted in $102 thousand MWh savings in generation annually over an average 14.5 years.[8] This means the average EVT cost per kWh is 2.8 cents. As a comparison, the average cost of wholesale market power in New England in 2002 was about 3.6 cents per kWh.[9] Over the same period, BED spent a total of $1.5 million for 7,251 annualized MWh savings. Both EVT's 2002 report and BED's 2*002 Annual Report on DSM Program Implementation* contain detailed information on their 2002 accomplishments.

As the annual EEU budgets ramped up, so did the amount of electric savings. Estimated annualized energy savings showed a steady increase from 2000 to 2002. At the end of 2002, the EEU activities of EVT and BED created a cumulative estimated energy savings of 96,000 MWh[10]
Over the initial three-year contract period EVT achieved over $66 million in total resource benefits. The total cost of these resources, including participant and third party costs, was less than $40 million.
Of the major milestones that EVT was charged to address over the three-year period, they failed to achieve only one, and achieved the maximum Performance Awards for all others. If the contract did not cap the total three-year Performance Award at $795,000, EVT would have received $902,841.

Efficiency Vermont currently offers services provided under a three-year contract for 2003 – 2005. Similarly, Burlington Electric Department is providing services pursuant to a Board approved three-year plan. The budgets and expected savings from those activities are shown in Table 6-4. For 2003, EVT reported total expenditures of $ 12,957,903 to acquire 51,216 annualized MWh and BED reported spending $1,481,068 for annual savings of 3,345 MWh. Savings are being acquired from all customer classes and geographic regions of the State. Without these 2003 electric energy savings, Vermont's annual electric load growth would be nearly 50% greater. Preliminary results from 2004 activities suggest both entities will meet or exceed their three-year savings goals.

Table 6-3 Statewide Energy Efficiency Programs Projections For Three Year Period 2003 – 2005

	Three Year Budget 2003 - 2005	Projected Annualized MWh Savings
Efficiency Vermont (EVT)*	$ 43,698,200	119,490
Burlington Electric Department (BED)	$ 2,554,617	7,487

[8] The EVT amounts here include the Customer Credit Program results.
[9] In January 2005, the average cost of wholesale market energy alone is roughly 5.7 cents per kWh.
[10] These savings differ from the numbers in the previous paragraph because they are calculated "at the customer meter" instead of "at generation." Savings at generation are higher because of line losses between generation and customers. Vermont's distribution utilities also reported some DSM activity during this period. The total reported DSM expenditures for the three-year period 2000–2002 were $31.3 million. The total estimated annualized savings for the same period is 103,626 MWh.

Total	$ 47,143,874	126,977

* EVT contract Tables K-2 and M, revised April 2004.

EEU EVALUATION

The September 30, 1999 PSB order in Docket 5980 that created the EEU, also established that the DPS would provide a formal evaluation of the EEU programs and that these evaluation activities would be funded by the EEC funds collected by the Fiscal Agent. The PSB approved Memorandum of Understanding (MOU) further specified that the evaluation would include an assessment of market transformation accomplishments.

DPS Responsibilities

The DPS conducts the formal evaluation of the core programs and all other system-wide EEU programs approved by the PSB. It also verifies annual MWh savings and total resource benefit claims by the EEU and assists the Contract Administrator in determining if the EEU has met its performance indicators. This evaluation includes an assessment of market transformation achievements and makes recommendations for program changes as necessary. The DPS contracts with professional evaluation contractors to conduct evaluation research to better understand and characterize the specific markets and market participants targeted by core programs. The coordinated evaluation activities utilize phone and on-site surveys to collect information on representative samples of program participants, non-participants, and various market actors as well as primary data on equipment efficiency levels, current construction practices, and market behavior. The results identify key findings by market sector and program. These reports are then synthesized into an integrated final report that summarizes the progress and accomplishments and identifies problems and opportunities for improvement in the current programs. There are three major categories of evaluation activity undertaken by the DPS in fulfillment of its EEU evaluation responsibilities. They are:

1. Verification of the annual MWh savings and Total Resource Benefit (TRB) claims by Efficiency Vermont ("EVT") and Burlington Electric Department ("BED") for each year of the three-year period.

This responsibility is specified in EVT's contract with the PSB and in the order approving BED's authority to implement statewide efficiency programs for customers in its service territory. Following issuance of EVT and BED annual reports, the DPS conducts a thorough verification check of their claimed annual savings and total resource benefits. This involves an in-depth review of tracking system data and electronic and hard copy project files by DPS staff and contractors. An independent engineering firm is retained to review certain large and/or complex C&I projects as needed and to assist in reviewing savings calculation methodologies and assumptions for unique and complex energy efficient measures and technologies.

In addition to the annual verification process, the DPS provides ongoing oversight of EVT's electronic data tracking system and conducts review of methodologies, algorithms and assumptions used by EVT and BED to claim electric savings and other benefits documented in a technical reference manual developed and maintained by EVT.

2. Assessment of residential energy efficiency markets and establishment of baselines to better document the market and the effects of the EEU programs on those markets.

A number of evaluation activities are included in this area. For the three-year contract cycle (2000–2002), in-depth surveys of vendors and contractors active in the residential new construction and efficient products marketplace were completed. An on-site survey of single-family residential new construction was conducted to establish baseline efficiency practices and to determine the level of compliance with Vermont's residential energy code ("RBES"). A preliminary study was undertaken to investigate the level of energy efficient lighting and appliance purchases in Vermont compared to purchases in a nearby New England state. A strategic process evaluation was conducted to identify potential improvements in the delivery of efficiency services to low income residents.

3. Assessment of non-residential, commercial and industrial energy efficiency markets to better document market conditions and the effects of the EEU programs on those markets.

For the three year contract cycle (2000–2002), in-depth surveys of architects, engineers, contractors, vendors, and other market actors active in C&I new construction, renovation, and equipment replacement markets were completed to assess and characterize these diverse markets. Telephone surveys were conducted with building owners and occupants to provide data on current efficiency practices and to investigate their interaction with Vermont's C&I building design and construction community. On-site surveys of a number of recently constructed projects were conducted and the results were compared with the market actor surveys to refine baseline efficiency practices. Strategic process evaluation research was incorporated into the market characterization efforts to assess EVT's program performance and to identify potential improvements.

In addition to these three primary activities, the DPS also conducted a formal assessment of BED's delivery of the statewide programs in the city and its record in coordinating the administration of the programs with EVT and Vermont Gas Systems (VGS). A formal assessment of the Customer Credit program was also conducted.

The DPS also participated in a number of evaluation studies associated with regional energy efficiency initiatives coordinated by the Northeast Energy Efficiency Partnership (NEEP) and the Consortium for Energy Efficiency (CEE).

Completed evaluation reports can be found at: www.state.vt.us/psd/Menu/EE_and_Renewable/eval/.

DPS Evaluation Plan for Current Three-Year Contract

The current plan for the next evaluation includes the following elements:

- Scoping Study--The purpose of this study is to help the DPS identify the specific scope of the planned evaluation projects, recommend an efficient evaluation implementation structure, and assist in writing the request for proposals for those projects.
- C&I Market Impacts & Strategic Market Assessment—This project will include a large number of tasks intended to capture market information so that EVT can strategically intervene to affect change in the C&I market and encourage the perpetuation of energy efficiency.
- Residential Market Impacts & Strategic Market Assessment—Similar to the C&I market assessment, this project will include a large number of tasks including the following examples: study on residential lighting usage and characteristics, refrigerator life expectancy, appliance saturation, appliance sales, residential new construction baseline, and non-participants.
- Annual Savings Verification and Assessment of Minimum Performance Standards and

Performance Awards Indicators--The DPS will continue to conduct its annual verification of EVT's MWh's savings and total resource benefits claims. This process includes reviewing EVT's savings assumptions, feedback to them on savings claimed from custom projects, review of their measure-level savings in its central database, review of other analysis tools, and comparison of savings to billing history. The verification results are used in association with other data to assess whether EVT has met its minimum performance standards and performance awards indicators in accordance with the formulas established in their current contract with the PSB.

- Feedback from diverse stakeholders suggests the Department should provide more opportunity for public input in planning EEU evaluations. In its September 30, 1999 order in Docket 5980, the Board envisioned an aggressive effort by the DPS "to invite public input during the planning stages of the evaluations, so that evaluators may be alerted to issues that warrant investigation before the evaluations are completed." (p. 39-40, footnote 82). For the current evaluation projects listed above, contracts are already in place and an aggressive schedule for completion established that precludes a formal public input for this plan. However, the contracts for the market impact and strategic market assessment studies listed above provide for these studies to be concluded and draft results presented to the DPS and other stakeholders prior to their finalization by August 1, 2005. Also, these studies include telephone surveys of statistically valid samples of homeowners and businesses to assess the current status of efficiency practices and solicit the respondents' experiences with EVT and BED.
- Future Stakeholder Participation in Evaluation -- The suggestion that greater public input is needed is well taken and the Department plans to determine and implement an effective public input process for future EEU evaluation plans, evaluations, and in future planning.
- Impact Analysis -- Wherever possible, evaluation of EEU programs will include actual empirical estimates (i.e., impact analysis) of savings levels actually achieved based on billing history and/or analysis of appropriate comparable patterns of consumption.

Rate Impact Analysis

Rate Impacts – With this Plan, the Department is raising the importance of rates as an important concern to Vermont ratepayers. Understanding the long-term implications of DSM programs will better inform debates around the implications of programs for end users. Rate impacts may also help inform how Vermont regulators impose future equity constraints (e.g., ratepayer class and geographic location). The prevailing perception among some segments of the business community is that DSM is increasing electricity costs. There are, however, offsetting benefit claims of "system benefits" and environmental benefits. System benefits can include (1) lower power costs when marginal costs of power exceeds energy costs (2) avoided capacity payments for generation and T&D charges, (3) auxiliary services. Establishing a credible rate impact analysis will help advance and focus debates around the EEU on core issues of program design, equity constraints in the deployment of programs, and overall cost-effectiveness.

STRATEGIC PEAK LOAD MANAGEMENT AND DEMAND RESPONSE

Important trends regarding time sensitive and location-specific opportunities to reduce peak electric demand and costs are rapidly emerging in Vermont. These new developments result, in part, from

the convergence of electric utility industry restructuring, the emergence of near real-time wholesale electricity markets, location at marginal pricing, regional demand response programs and a variety of cost-effective load management technologies, practices and control systems.
Strategic demand response and peak load management initiatives are not new concepts. For many years, Vermont utilities have conducted load control and load management activities, ranging from water heater control programs to interruptible contracts and various electric rate designs intended to provide consumers with more accurate price signals. Seasonal and time-of-day rates are designed to better reflect the variation in the costs utilities bear in providing electric service to customers at different times of the year and different times of day. To a lesser extent, similar efforts have been conducted in a number of transmission and distribution constrained areas of Vermont. Geographically targeted load management efforts have traditionally involved special contracts between utilities and their largest customers located in constrained areas such as those surrounding a number of the state's major ski resorts. Under these types of load management contracts, customers agree to accept non-firm electric service under certain peak electric demand periods in exchange for discounted electric service during off-peak hours.

Strategic demand response and peak load management programs and initiatives should not be confused with the core, statewide energy efficiency programs operated by Vermont's Energy Efficiency Utility ("EEU") since 2000. The efficiency programs operated by the EEU evolved from a previous generation of energy efficiency programs offered by the state's electric utilities throughout the 1990's. Energy efficiency programs of this type are sometimes referred to as conservation programs and at other time as demand-side management programs ("DSM"). Energy efficiency programs often effectively couple measures to improve the operational efficiency of energy consuming equipment (and buildings) with traditional conservation practices to reduce energy bills for consumers, as well as to reduce utility supply costs. The term DSM on the other hand is traditionally defined in a much broader sense than efficiency or conservation. As the name implies, demand-sided management connotes a diverse menu of conservation, load management, efficiency, direct load control and a variety of other strategies that affect the level of demand consumers place on a utility' provision of electric service, (i.e., the supply side).

With this distinction in mind, it becomes clear that there are fundamental differences between the types of energy efficiency services provided by the state's Energy Efficiency Utility on a comprehensive, statewide basis and other strategic demand side management efforts provided by many of the state's electric utilities. These two types of least-cost investment strategies have been operated concurrently in Vermont for many years and continue to be operated concurrently to this day. The EEU operates the core efficiency programs on a consistent statewide basis across all of the state's electric utility service areas with the exception of the city of Burlington. The Burlington Electric Department operates the same core efficiency programs, in coordination with the EEU, in Burlington.

Energy efficiency programs and the types of strategic peak load management and demand response programs discussed later in this section are complimentary in many respects. Many common energy efficiency measures do in fact provide savings during the peak load periods faced by the electric utility. This is true to the extent the energy saving measure operates at the very same time the utility faces a peak demand period. In other words, when the customer's operation of the measure is coincident with the utility peak period(s). While the measure does contribute to reducing utility costs to serve peak load, the measure is not necessarily designed to optimize cost savings during the time the utility faces its highest supply costs. Rather, the efficiency measure is optimized to reduce consumption whenever it is operated regardless of whether the operation turns out to be consistent with a specific utility's peak load periods.

A simple example may help illustrate this subtle, yet critical difference between energy efficiency and demand response measures. Assume the EEU assists a customer to install a state of the art economizer on the air conditioning unit ("AC") in a new building. The economizer provides the customer (and the utility through avoided supply costs) with savings by virtue of the economizer's "free-cooling" capability. The free-cooling savings result from the AC unit's ability to flush the building with outdoor air to cool its occupants when the outdoor temperature and humidity conditions permit. In Vermont's climate, there are many hours in the year when the outdoor air can easily offset the internal heat gains created by the occupants and equipment contained in a typical commercial or industrial facility.

From an average avoided supply cost (year round, 8760 hours) perspective the economizer measure may prove to be a viable, cost-effective measure from both the customer's perspective (i.e., savings at retail rates) and the utility perspective (i.e., avoided supply, transmission and distribution costs). This same measure can be expected to provide absolutely no savings during the summer afternoon, weather driven, peak hours when outdoor ambient air conditions are simply too hot to provide the free cooling.

From a strictly strategic peak load management and load response perspective the economizer option has little value to either the customer or the utility. The AC unit, however, does represent a critical peak, demand limiting opportunity in its own right. Assume that new building is located in the service area of a utility that is committed to assisting its customer to install cost-effective measures through a strategic peak load management program. The strategic peak program is designed to reduce the utility's exposure to the high supply costs associated with its summer afternoon peak loads.

From this perspective the AC unit offers a different set of operating characteristics that offer the utility a demand-side resource to offset its peak power supply costs. The AC control system can modify the operation of the unit in a couple of ways in response to the high price signals on the summer afternoon in question. First, the temperature set point for the unit can be adjusted to enable the temperature to drift up a few degrees for a number of hours until the peak period passes. Second, the duty-cycle of the unit can be modified to reduce the random coincidence of its components (e.g., compressors) from occurring during the peak afternoon hours. Third, the building energy management system (or building operating staff) can anticipate the weather conditions expected in the afternoon and pre-cool the building during the overnight and early morning hours thereby minimizing the need to operate the AC unit during the peak hours.

None of these three strategic peak load measures reduce the energy consumption of the AC system. Hence they are not efficiency measures in the same sense as the economizer.

Many other measures, by contrast, exhibit both energy efficiency and strategic peak load management characteristics. Consider an automated daylighting measure in the same new building. The daylighting technology automatically reduces the output (and energy consumption) of lighting fixtures located near windows during daylight hours when sunlight can provide a portion of the lighting levels required by the building occupants.

The daylighting control system operates whenever ambient outdoor lighting levels are sufficient irrespective of the building (or utility) load at any particular point in time. Hence this measure, like the economizer, is an efficiency measure. Unlike the economizer, however, its operation will have a high probability of being consistent with the utility's peak load hours on any particular hot summer afternoon. This is due to the simple fact of the relationship between the level of ambient daylight sensed by the daylighting system and the wet-bulb temperature driving the utility's peak load hours on those hot summer afternoons.

Clearly, the daylighting example illustrates an instance where a familiar energy efficiency measure provides time-sensitive benefits from a strategic peak load management perspective. While this is not an altogether uncommon attribute of energy efficiency measures, unfortunately, it sometimes gives rise to a degree of confusion between the purposes, performance characteristics, and derivation of savings between energy efficiency and strategic load management measures. Maintaining the distinctions, as well as the common attributes of each is increasingly important as Vermont and the nation's electric utility industry move toward competitive wholesale energy prices in which supply, as well as demand-side resources, compete in location specific, real-time markets.

A number of specific Strategic Peak Load Management and Demand Response initiatives are described below.

GEOGRAPHICALLY TARGETED DSM

Chapter 7 discusses developments in the regional wholesale electricity market that include putting a price on the congestion experienced on the transmission network in some areas. It describes how Independent System Operator of New England (ISO-NE) has implemented Locational Marginal Pricing (LMP) and classified Vermont as a single zone. Each zone is comprised of many separate nodes. Under LMP each node within the zone carries its own Marginal Loss and Congestion Component. The zonal price represents a weighting of the separate zoned. In Vermont under the current Standard Market Design (SMD), one area that has constrained transmission results in higher prices for the entire state. It appears that if concentration of efficiency programs in the constrained area(s) eliminated the constraint, benefits would accrue to all of Vermont as a result of lower LMP. This new situation may be somewhat at odds with the requirement that EEU services provide geographic equity over time.

An assessment of the benefits and costs of a modification of EVT's assignment is needed prior to any potential reallocation of the EEC funds used to support the statewide EEU activities. This will require the development of a number of inputs, including updated statewide avoided costs and development of constrained area avoided costs to reflect the added costs to all Vermont consumers of area specific transmission and distribution congestion. The DPS is currently active in a regional effort to update the avoided costs used to plan for and evaluate energy efficiency programs in New England states.

The EEU currently has a pre-determined budget that is legislatively capped at $17.5 million annually and has limited flexibility with regard to using EEC funds to target any particular geographic area. Under the legislation establishing the EEU, the Board must ensure that all retail consumers, regardless of retail electricity or gas provider, will have an opportunity to participate in and benefit from, energy efficiency programs. The memorandum of understanding ("MOU") approved by the Board in its 9/30/99 order in Docket No. 5980 contains language requiring the EEU programs to reflect expenditure levels that, over time, correspond to electric energy use by geographic region and customer class throughout the state.

The 5980 MOU also provides that the distribution utilities are responsible for T&D planning and its associated implementation, including cost effective DSM to defer or avoid transmission and distribution investments.

Since the SMD is still relatively new it is recommended that a study be done to determine the viability of concentrating efficiency programs in constrained areas as a means of reducing LMP. That study should address the cost effectiveness and options for delivery and funding of energy efficiency in constrained areas.

INTERRUPTIBLE CONTRACTS

Interruptible contracts are negotiated with the utility and provide the customer more power to control his or her electric bill. Customers are compensated for their reduction in demand but they also save by reducing their kilowatt-hour consumption. Some customers with backup generation find it cost effective to shift load onto their generator(s) when the utility requests them to reduce their load. Of course in these cases, these customers have to pay for the fuel costs for the generator but the utility incentives more than offset these costs, in general. An issue becoming more prevalent with these types of arrangements is the environmental concern caused by these on-site generators.

DIRECT LOAD CONTROL PROGRAMS

Utilities have implemented direct load control programs such as electric water heater controls installed on customers' water heaters. The utility sends a signal during peak hours that turns off the water heater for a set period of time. In some instances, customers partner with utilities to allow them to control large non-critical electric loads at customer facilities. These customers do this under an interruptible contract.

RATE DESIGN AND LOAD

Most utilities have mandatory demand rates—rates that put a price on how much electricity consumers use at one time, not just their total monthly usage. Utilities in Vermont offer Time-Of-Use (TOU) rates for customers meeting load and kilowatt-hour usage minimums. These rates were initially ordered by the PSB to send accurate price signals to Vermont customers reflecting the higher demand and energy costs during peak hours and peak seasons. The TOU rates in general, have higher kilowatt and kilowatt-hour rates during the workweek day than late at night and over the weekend. Also, because most utilities in Vermont are winter peaking, winter rates are often more expensive than summer rates. With the advent of pool pricing and summer peaking, this is changing. Many Vermont utilities have now "de-seasonalized" their rates so that the charge is the same year round. Shortly after the advent of TOU rates, service providers realized that there would be a market for equipment that could reduce electric loads during peak times. Many technologies are now available.

Load Shifting Strategies

Customers who can shift some of their electric loads to off-peak times, when the electric rates are lower, can save money. Load shifting can be done by using technology such as thermal storage air conditioning systems, that make ice slurries using energy intensive compressors, during the evenings and then during the peak day-time hours circulate the pre-chilled liquids using relatively inexpensive to operate pumping systems. Technologies such as this sometimes consume more energy than traditional air conditioning systems but cost the customer less because of the rate design. Some customers, such as industrial customers, choose to run shifts during the night or operate energy intensive equipment during off-peak hours to avoid the costs of on-peak rates.

Load Reducing Strategies

Energy conservation and energy efficiency techniques are often used to reduce electric load as well as energy consumption. Customers wishing to reduce load will often pursue load reducing strategies such as replacing old or failed motors with more energy-efficient units, improving the thermal envelope of their building(s) by adding insulation or air sealing the structure, or replacing inefficient lighting with high-performance lighting systems. Some customers install sophisticated demand limiting technologies such as Energy Management Systems (EMS) that monitor and control equipment such as Heating, Ventilating, and Air Conditioning equipment (HVAC). The EMS can be set-up to let the temperature in selected rooms such as unused conference rooms in a hotel rise to a predetermined level during peak hours in the summer when air-conditioning. This reduces the load on the HVAC equipment. Demand limiters can also mechanically cycle equipment so that customer demand does not exceed a preset limit.

Fuel Switching

Some customers have found that a cost-effective means to reduce their electric load is by replacing their equipment that formerly operated on electricity with equipment that uses another fuel such as natural gas, propane, or fuel oil. A common example of this is the installation of gas or oil boilers and furnaces to replace electric resistance heat. Another example of fuel switching is the replacement of electric water heaters with fossil fuel water heaters. Fuel switching can be very cost-effective also as a DSM measure because its electric heat use coincides with the winter peak. Typically Vermont had reached its winter peak on the coldest day of the year. In 2002, Vermont became a summer peaking state in part due to fuel switching and in greater measure, due to the increased use of air-conditioning.

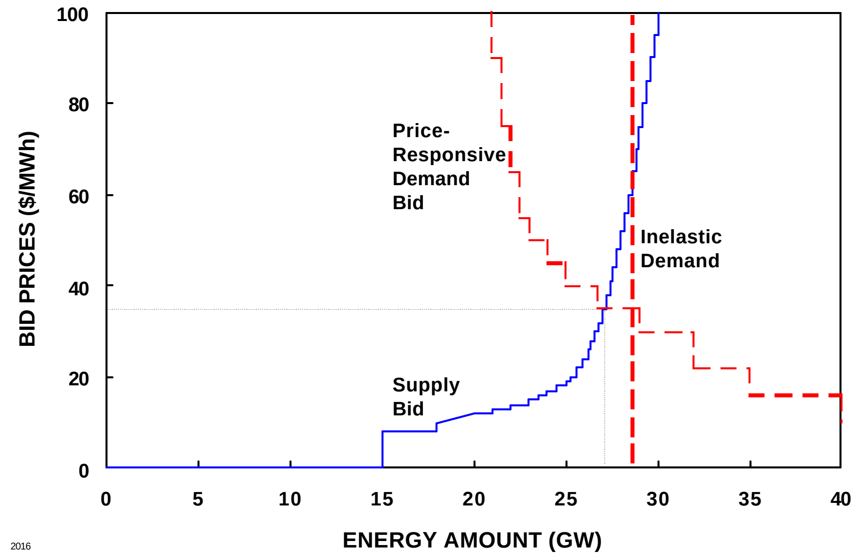
LOAD RESPONSE PROGRAMS

Participants in wholesale electricity markets have employed load response in the past several years as a cost-effective way to meet peak demand and to relieve congestion in constrained load zones. The value of load response is greatest during periods when congestion or resource constraints cause day-ahead or real-time prices to climb steeply. Figure 6-2 illustrates the relationship between demand and supply bids into the day-ahead market in New England. A relatively small increase in demand from 27 to 28 GW causes a significant increase in supply bid clearing price, about $38/MWh to $60/MWh. The corresponding reduction in demand bids is far below supply, highlighting the value of demand reduction in periods of rapidly increasing costs.

ISO-New England Load Response Programs

As a result of the Vermont PSB's investigation into Load Response Programs in Docket 6555, most of the Vermont electric utilities offer the ISO-New England Real-Time Price Response and Real-Time Demand Response Programs to their customers. The Vermont PSB approved these programs in May and June 2003.

Figure 6-2 - Price Sensitivity to Demand



Source: New England Demand Response Initiative, Final Report, Figure 1-1.

ISO-NE offers four demand response options and one price response program to participants, outlined below. Customer participation in each of the programs is voluntary and payments are made only on days where ISO-NE issues a request for load reduction and where customers meet minimum program requirements. Only customers with load reduction potential of 100kW or greater are eligible for participation in three of the four demand response programs. The Profiled Program requires a minimum participation level of 200kW. Methods for reducing loads include operating emergency generators, direct load control (hot water heaters), shutting down or rescheduling manufacturing processes, adjusting energy control systems and curtailing non-essential loads.

The amounts paid by ISO-NE are set according to program type. ISO-NE reports that $3.3 million was paid to approximately 200 participants in 2002. Customers must have hourly metering installed for most programs such that ISO-NE can monitor actual hourly customer loads for Day-Ahead (DA) response programs; the cost of metering is a potential disincentive for smaller customers, although some subsidies were available when the programs were initially offered. The actual customer load reduction is determined by ISO-NE based on the difference between the customer's "baseline consumption" for that hour versus actual load.[11]

The ISO-NE Load Response Programs are summarized below.[12]

- **Real-Time Price Response -** Participants monitor hourly prices on a real time basis. ISO-NE notifies participants electronically or via facsimile when they may be eligible for compensation as prices rise. Minimum payment: $.10/kWH.[13] Maximum payment: $1.00/kWH.

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[11] Baseline consumption is calculated by ISO-NE. It includes average hourly customer loads based on actual recorded loads forwarded to ISO-NE by the local utility.

[12] The Real-Time Price Response and Real-Time Demand Response Programs offered by Vermont utilities vary slightly from the ISO-NE terms described in this section.

[13] In 2002, wholesale prices exceeded $0.10/kWH for 40 hours over 12 days.

- **Real-Time 30-Minute Demand Response** – Participants *must* curtail or disconnect load within 30 minutes upon notification by ISO-NE. Minimum payment: $.50/kWH for at least 2 hours plus ICAP credits.
- **Real-Time Two Hour Demand Response -** Participants must curtail or disconnect load during emergencies within two hours upon notification by ISO-NE. Minimum payment: $.35/kWH for at least two hours plus ICAP credits.
- **Day-Ahead Demand Response** – Participants bid into the day-ahead market similar to bids for generating resources. The bids compete equally with generating resources and may set zonal prices. Successful load reduction bids are fully incorporated into ISO-NE scheduling and settlement systems. Customer minimum day-ahead bid: $.05/kWH. Customer maximum day-ahead bid: $.10/kWH.
- **Real-Time Profiled Demand Response** – Participant groups with controllable loads that collectively can be interrupted within 30 minutes. Minimum payment: $.10/kWH for at least two hours plus ICAP credits.

Load response is viewed as an equally acceptable alternative to generation by ISO-NE to satisfy demand requirements, particularly in areas that are generation deficient or within constrained interfaces. For example, ISO-NE has strongly encouraged load response options in southwest Connecticut, one of the most constrained areas in New England. In 2003, Vermont participants contributed over 13 MW of load response; about 4% of the pool total, consistent with the state-to-pool load ratio. Table 6-5 presents New England 2003 load response, by program for each state. It excludes Day-Ahead Demand Response, as the program was not in place at the time.

Table 6-4 Load Response Capacity 2003[14]

Zone	Assets	RT Price (MW)	RT 30-Min (MW)	RT 2-Hour (MW)	Profiled (MW)	Totals
CT	141	31.8	162.2	.4	0	**194.5**
ME	5	1.5	0	1	76.0	**78.5**
NEMA	114	38.9	3.3	1.5	1.4	**45.1**
NH	3	1.2	.4	0	0	**1.6**
RI	11	2.8	0	0	0	**2.8**
SEMA	81	8.3	.5	0	0	**8.8**
VT	17	7.5	.1	0	5.9	**13.5**
WCMA	96	12.6	2.3	9.3	0	**24.2**
Total	**468**	**104.5**	**168.9**	**12.3**	**83.2**	**368.9**

Recommendations to Increase Participation in Load Response Programs

An October 14, 2002 study conducted by the Townsley Group for ISO-NE recommended the following measures to increase participation in ISO New England's load response programs:

[14] Source: RTEP Meeting No. 19 presentation materials, January 16, 2004.

- Every effort should be made to promote broad-based end-user participation in a competitive solicitation, which minimizes barriers to entry. This should have the effect of reducing program cost and increasing the program net benefit.
- End-user incentives should be market-based, that is, funded by retail pricing arrangements that give customers the opportunity to manage their load in response to the economic value, i.e., the hourly LMP savings, that can be expected from load curtailment.
- Special third-party programs should accordingly be designed to promote innovative retail pricing, including metering and communications infrastructure, end-user education, and technical assistance regarding load management options.
- Artificial limitations on the scope of price-responsive load management, based on predetermined hours of the year, or a prescribed minimum price threshold, should be avoided in order to allow the end-user maximum discretion in selecting the most economically advantageous parameters of load curtailment at each facility.

Vermont utilities should encourage load response as means to reduce demand and to decrease costs, particularly in areas where congestion may cause reliability to degrade or increase costs. Load response and conservation currently are included as viable options to defer transmission investment in the eleven Area Specific Collaboratives (ASC) described in Chapter 8. The ASC's include areas where local distribution and/or subtransmission, and possibly high voltage transmission systems are or soon will be unable to reliably serve area load. Load response programs administered by ISO-NE, as presently configured, may offer limited opportunities in ASC's.
Vermont should continue to work with ISO-NE, the operating utilities and other parties to seek solutions to promote greater penetration of cost-effective load response in areas that would benefit from these programs. To facilitate statewide transmission planning, it also is important to identify the composite reduction that can be achieved at peak. Firm estimates of load response should be assessed on a comparable basis to transmission options.

SELF-GENERATION

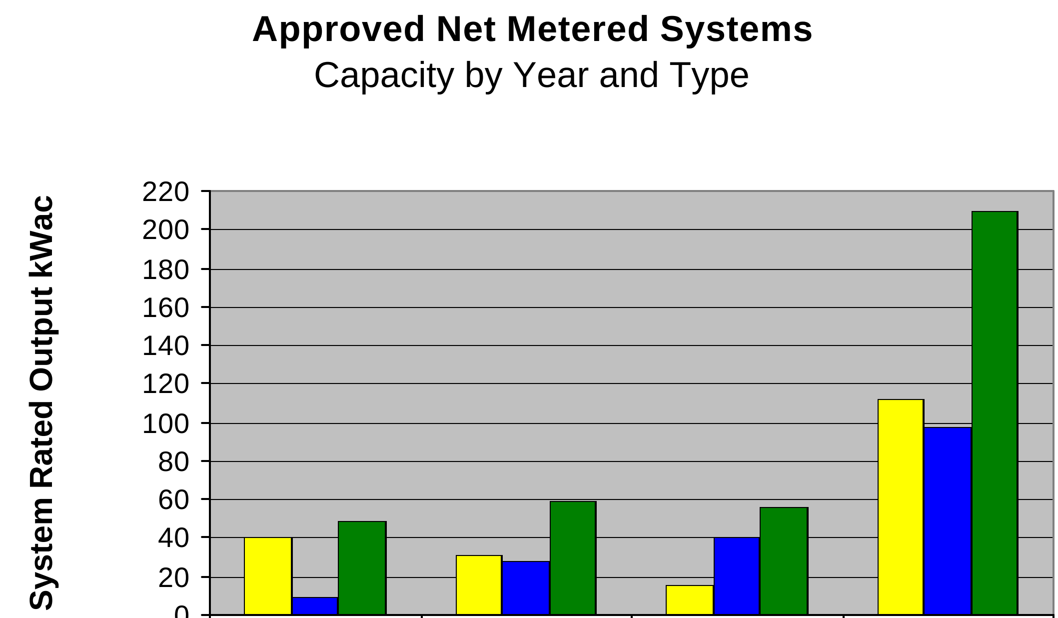
Some utility customers have found that they can save money and reduce their electric load by generating all or some of their own power. This can be especially true if the costs are substantial to install utility equipment up to the building, such when the building is located far from the nearest electricity source. Self-generation customers have used conventional diesel fueled generators for years. The use of wind and solar powered equipment is becoming more prevalent as costs for this equipment comes down and more people with a wish to buy "green" power install this equipment in their buildings. In Vermont, self-generation customers who use wind or solar powered equipment are fortunate to be able to sell back the power to the utility at retail rates (net metering.)

Net Metering

The 1998 Legislative session enacted the Net Metering Law (30 V.S.A. §219a). Net metering allows utility customers to connect certain renewable energy systems to the electrical grid through their existing meter. This arrangement makes it possible for customers to send excess energy generated by their system back through the meter to the grid and draw that energy back through the meter when needed.

In 1999 modifications were made in to the law (S.230), allowing additional systems, including certain fuel cells and a limited number of 100 kW renewable energy projects to qualify for net metering. In the 2002 session an expansion to the existing net metering law, commonly referred to as "group net metering", was enacted. The expansion allows farm systems to credit generation against multiple electric meters on the farm.

Figure 6-3 New Installed Net Metered Capacity Permitted by Year and Type



	2000	2001	2002	2003
Photovoltaic	40.75	31.47	15.99	112.16
Wind	9.50	27.95	40.45	97.80
Total	48.89	59.42	56.44	209.96

The net metering statute is crafted to encourage customers to size their systems to meet primarily their own needs. In the course of a year the consumer can receive credit only for generation delivered back to the system that equals the total amount taken from the system. In effect, the customer uses the utility grid as a low-cost battery or energy storage system. Any net excess generation fed back into the grid goes to the benefit of the distribution utility at the end of the year and no payment is made for it. The DPS participated actively in the PSB rule that implemented the net metering law and proposed simple, effective, but not burdensome interconnection rules. The DPS assists customers with net metering applications and monitors participation. As of July 2004, there were 136 permitted net-metered systems.

The DPS supported and the legislature passed a sales tax exemption on equipment used in net metering systems. In 2002 the exemption was expanded to cover solar hot water systems and off-grid renewable energy systems that met a number of the previously established specifications for net metering equipment.

DSM POTENTIAL

A study completed for DPS in 2002, titled *Electric and Economic Impacts of Maximum Achievable Statewide Efficiency Savings 2003-2012 Results and Analysis Summary,* concluded that there is sufficient cost effective DSM potential available so that Vermont could meet its future electric demand through an aggressive sustained energy efficiency campaign. The report acknowledged that achieving this level of energy savings would require greatly expanded efficiency investments and initiatives that went well beyond what is currently being offered through the EEU and other utility programs.

To achieve the maximum potential savings, the study suggested employing the following program strategies:

- Sustained marketing to consumers and upstream suppliers (equipment manufacturers, distributors, and/or retailers);
- Generous financial incentives covering full technology costs, either incremental or installation with labor, depending on market;
- Comprehensive technical and information services to all market participants; and
- Complete customer service delivery.

The study acknowledged that there might be "portions of the state where predicted sales growth would outstrip localized achievable efficiency potential.

Although the current energy efficiency strategies being employed in the state may not be aggressive enough to meet all future electric growth demand, they are providing significant energy savings. In their 2003 draft report, EVT states that the savings achieved through their programs "met 46% of the growth in electrical energy requirements in Vermont during the year." The report also states that since 2000, EVT "has lowered Vermont's summer peak load by a total of 18,800 kW and winter peak load by 34,000 kW."

DSM IN STATE GOVERNMENT

The electricity used by state buildings ranks among the largest consumers of electricity in Vermont after IBM. According to Vermont's Department of Buildings and General Services, the state buildings' annual electricity bill is approximately $6,000,000 per year. State government can lead the state in its DSM efforts and innovation. Currently, there are two executive orders issued by Governor Douglas that expand and bolster DSM efforts within Vermont-owned and leased buildings. The Governor established internal DSM goals and programs that can be emulated by organizations and businesses across the state by ordering the Vermont Clean State Program (02-04) and the Climate Change Action Plan (14-03). Both of these orders expand and support DSM efforts within state government as well as promote other significant initiatives that create positive benefits to the environment.

VERMONT CLEAN STATE PROGRAM

Governor Douglas' Vermont Clean State Program executive order took effect April 8, 2004. The order recognizes that "Vermont state government has a duty and responsibility to lead by example in conserving natural resources and practicing pollution prevention…" Furthermore, the executive order acknowledges the importance of reducing waste at the source as "often the most inexpensive way to diminish pollution and promote resource conservation while saving money." As part of the order, the Governor rededicated and expanded the Clean State Program for state agencies. This reinvigorated plan implements an environmental education program, enacts new administrative environmental policies, and identifies resource conservation and pollution prevention opportunities. The plan is divided into the following four parts:

MATERIALS MANAGEMENT PLAN

The Materials Management Plan will promote resource conservation and pollution prevention where feasible in addition to continued wise purchase practices, and intelligent use and reuse of products. Each agency and department will assign a recycling coordinator who will serve as a liaison to the Department of Buildings and General Services (BGS). This position will be responsible for considering energy conservation when selecting products to procure.

EDUCATION AND INFORMATION PROGRAM

The Education and Information Program will be coordinated by the Departments of Environmental Conservation and BGS to help state employees in the practice of resource conservation and pollution prevention. The executive order states, "it is the goal of this program to ensure that state employees understand the importance of their leadership roles and environmental responsibilities and are aware of opportunities to use resource conservation and pollution prevention practices in daily decisions."

STATE AGENCY POLLUTION PREVENTION PLAN

The Agencies of Natural Resources and Administration will create the State Agency Pollution Prevention Plan for the executive branch of state government. Included in this plan will be a summary of key opportunities for resource conservation and pollution prevention. Additionally, the plan will list goals, objectives, and performance targets that the agency will strive to achieve within a period of one, two, and five years.

POLLUTION PREVENTION GUIDANCE DOCUMENT

The executive order requires the preparation of a Pollution Prevention Guidance Document for all state agencies and a recommendation to the Governor on a process for pollution prevention implementation for all state agencies. This document may include energy efficiency and conservation strategies.

CLIMATE CHANGE ACTION PLAN

Governor Douglas' Climate Change Action Plan for State Government Buildings and Operations undertakes ambitious energy efficiency and conservation efforts to reduce greenhouse gas emissions and a host of other pollutant emissions (including toxic chemicals) associated with fossil fuel combustion for electricity generation and transportation. Vermont's goal is to reduce emissions by an amount consistent with the recommendations of the Conference of the New England Governors and Eastern Canadian Premiers Climate Action Plan. The goals established by the Conference are to reduce region-wide greenhouse gas emissions from the 1990 baseline by: 25% by 2012; 55% by 2028; and, if practicable using reasonable efforts, 75% by 2050. To promote these goals, Governor Douglas ordered the following initiatives:

Climate Neutral Working Group
The Governor established the Climate Neutral Working Group to be jointly chaired by the Commissioners of the Department of Environmental Conservation, the Department of BGS, and the DPS. The group also included Secretaries, Commissioners, and technical representatives from the Agency of Natural Resources (ANR), DPS, Agency of Administration, Agency of Commerce and Community Development, Agency of Transportation (AOT), Department of BGS, Vermont Energy Investment Corporation, and other agencies as interested. The working group is tasked with coordinating, documenting, and encouraging efforts to meet Vermont's greenhouse gas emission reduction goals. A large part of the group's focus is the creation of a biennial report to the Governor.

Biennial Report to the Governor and General Assembly
The executive order requires that the Climate Neutral Working Group, on a biennial basis, report to the Governor and General Assembly the state of the science for responding to climate change, including the status of methods and measures available to meet those goals. In addition, the report will identify opportunities to share lessons learned with Vermont businesses, other state and provincial governments, and the federal government. Among other activities, the report will recommend greenhouse gas reduction targets and identify activities, some of these demand side management strategies, to help meet those targets.

Energy Star Equipment Directive
Included in the order is a directive by the Governor for state government to purchase only energy consuming devices that meet or exceed Energy Star® or comparable standards established by the U.S. government, and to operate these devices in a manner that maximizes their energy efficiency features.

Department of Buildings and General Services (BGS) Directive
The Department of BGS is required to work with the Climate Neutral Working Group and all state facilities to ensure that every state building reduces its energy consumption to meet the outlined greenhouse gas reductions.

Renewable Energy
The Department of BGS is required to investigate cost-effective opportunities to purchase renewable energy to reduce Vermont's reliance on fossil fuels. Renewable energy generation, if installed in decentralized locations, such as in state facilities, can reduce the electric demand on the utility transmission and distribution system. Renewable energy includes electricity derived from sources such as solar, wind, geothermal, landfill methane gas, or small-scale (less than 30 MW) hydroelectric projects.

Input From Businesses and Other Groups
The Climate Neutral Working Group will request input from representatives of the business, environmental, forestry, and transportation sectors regarding opportunities for the private sector to reduce emissions and conserve energy.

Consultation with Other New England States
The Climate Neutral Working Group will consult with representatives from other New England states to establish a broad-based approach to these environmental issues. This sharing of information is intended to spur on synergies that might not develop without this planned interaction.

BUILDING CODES & STANDARDS

Residential Building Energy Standards (RBES)

The 1997 General Assembly approved Vermont's first energy code, the Residential Building Energy Standard. It is based on the national Model Energy Code and gives home designers and builders a predictable, minimum guideline for energy performance in Vermont's climate. The DPS, EVT and BED work closely with neighboring states, various regional and national energy code organizations and other professional associations and trade groups to advance the adoption of reasonably consistent, current, building energy codes on a regional and national basis.

The Vermont Energy Investment Corp., under contract with the DPS, administers the Vermont Energy Code Assistance Center that provides assistance with code compliance and coordination of the RBES and EVT program services. Rule making on the code was completed in May 2004. Revised marketing, outreach and compliance materials were developed and distributed in support of the revised Residential Building Energy Standards to take effect on January 1, 2005.

Residential New Construction Evaluation Survey

Vermont's housing stock has increased by roughly 2,700 units each year between 1999 and 2001. In a survey of these homes approximately 59% met the RBES requirement for total thermal transmittance (UA), a measure of heating energy use. A comparable study of homes in 1995 found that only 35-40% achieved the same level of energy efficiency. The Vermont achievement is particularly striking in comparison to a similar study in Massachusetts where, unlike Vermont, the law provides for inspection and enforcement. The Massachusetts study in 2000; done 18 months after implementation of their residential building code, found that only 46% of the new homes in Massachusetts complied with the same thermal transmittance standard.

Vermont's new housing stock improved on several other scales as well. The table below summarizes the changes.

Table 1.6 Vermont Baseline Construction Characteristics

Compliance Feature	1995 (n ‘ 151)	2002 (n ‘ 158)
Percent of homes meeting UA Requirements	35 B 40%	59%
Attic insulation meets or exceeds code requirements	61%	68%
Wall insulation meets or exceeds code requirements	57%	90%
Basement wall insulation meets or exceed code requirements	48%	62%
% glazing area with 2-pane, Low-e glass	70%	80%
Mean Air Infiltration - measured in air changes per hour (ACH)	~.45 ACH	.31 ACH
Mechanical ventilation installed per	6%	32%

code		
Mean Heating system Oversizing Factor	>100 %	92%
Percent with tankless coil water heating (inefficient method)	32%	3%

Commercial Building Energy Standards (CBES)

The Energy Efficiency Division has been managing the Commercial Building Energy Standards development and implementation project under a number of state energy program grants with the U.S. DOE. This project is closely coordinated with EVT, BED, and the state's building design, engineering and construction community in an effort to develop consensus-based, statewide minimum efficiency standards for commercial new construction in the state. The Vermont CBES development team utilized the latest generation national model energy codes (IECC 2000/ASHRAE 90.1-1999) in developing the *2001 Vermont Guidelines for Energy Efficient Commercial Construction.* The 2001 Commercial Guidelines were published in October 2001.

The energy code affects most of the state's new commercial, industrial, institutional and high-rise multi-family building construction projects. The *2001 Vermont Guidelines for Energy Efficient Commercial Construction* has been adopted by the City of Burlington for all commercial new construction and by the State of Vermont for state funded new commercial construction projects. The 2001 Guidelines have also been successfully integrated into criterion 9F (energy conservation) of Act 250 review to expedite permit approval in a simplified, consistent and predictable manner. The 2001 Guidelines establish minimum energy performance requirements for Act 250 permitted commercial and industrial developments throughout the state. For commercial construction not currently subject to the 2001 Guidelines on a mandatory basis, Efficiency Vermont, (the statewide energy efficiency utility), BED, Vermont Gas use the 2001 Guidelines to establish baseline energy efficiency requirements under their commercial new construction efficiency program services on a voluntary basis.

Vermont's success in developing and implementing the *2001 Vermont Commercial Guidelines for Energy Efficient Commercial Construction* has been closely coordinated with similar, concurrent efforts in New York, Massachusetts and other states in the northeast. These guidelines and the associated national model codes are subject to regular review and analysis by the CBES development team and project stakeholders. The development team expects to publish the first major update to the 2001 Guidelines in 2005.

ENERGY CONSERVATION

Energy conservation is defined as using less energy through changes in practices and behavior. People conserve electric energy by turning off lights and appliances when not needed, turning down heating thermostats, turning up air conditioner thermostats, drying clothes on a line instead of using a clothes dryer. Unfortunately, many equate making these types of behavioral changes with sacrificing comfort or being inconvenienced. Yet, the actions necessary to conserve resources need not be onerous to be effective. The focus of energy conservation is using energy wisely and eliminating waste by turning equipment off when it is not in use, not necessarily self-sacrifice. One of the greatest benefits of energy conservation is that it costs little or nothing to implement. Unlike efficiency, which requires investment in energy saving equipment, conservation only costs time, effort, and possibly some staff training. Energy conservation and efficiency have the greatest impact when both are utilized simultaneously. Even if the most energy efficient equipment available is installed in a home or business, additional energy and resources can be saved if the equipment is turned off when it's not in use.

There are many good sources of information on how individuals and businesses can reduce their consumption through easy behavioral changes. EVT's website, http://www.efficiencyvermont.com, Vermont's electric utilities, and the DPS website, http://www.state.vt.us/psd/Menu/Energy_Efficiency_and_Renewable_Energy have energy savings tips available. Electricity use guides are available that show which household appliances use the most electricity. For businesses, the Energy Star website at http://www.energystar.gov or www.rebuild.org are valuable resources. Heating and cooling tips are available at http://www.energyguide.com/info/eip-tips/. Energy audits can help identify the greatest opportunities for conservation as well as efficiency in individual homes and businesses. Energy conservation can make a difference, especially when practiced by many, and requires only that we humans be more mindful of our actions and surroundings.

Everyday energy conservation is not typically considered a demand side management strategy, as it is not easily quantified and its success relies exclusively on human behavior. Consumer conservation can play an important role in protecting our electric grid when immediate energy reduction is needed. Since the 1980's, Vermont utilities have periodically issued peak alerts when electric supplies are overly stressed due to a generation or transmission inadequacy during times when electric use is extremely high due to extreme cold or hot weather.

Recently, the need to conserve electricity during peak times in Vermont occurred during a cold snap when generation resources and transmission and distribution facilities were strained due to the demands on the system to provide heating for buildings and their occupants. In January 2004, New England was threatened with potential blackouts due to the high demand. The New England electric system operator ISO-NE issued an alert after several days in a row of very cold and windy weather. In Vermont, the Governor and utility representatives went on television to urge consumers to defer discretionary appliance use, turn off the lights when they are not needed, and otherwise take steps to conserve electricity. The consumer response was sufficient to avoid the feared blackouts during that episode.

In the past five years, Vermont's summer peak electric use has dramatically increased. When the weather is hot and humid for a number of days in a row, the demand for electricity is potentially greater than what can be supplied by generation and, especially, Vermont's transmission and distribution system. In the summer of 2002, utilities asked Vermonters to conserve during the day by shutting off lights, setting the air conditioner thermostat a bit higher, closing window blinds and curtains, deferring appliance use, and otherwise taking steps to minimize electric use. Summer time energy conservation is increasingly as important as winter conservation in Vermont.

OTHER DPS ACTIVITIES

The DPS Energy Efficiency Division (EED) also participates in regional and national efficiency efforts.

The DPS has participated in regional energy code projects and has selected national code models that mirror those commonly used by professional engineers and architects. They have published *The 2001 Guidelines for Energy Efficient Commercial and Industrial Construction.* These guidelines are typically a requirement of Act 250 permits and have created a predictable target for Act 250 applications for energy performance, making it simpler to satisfy the law's energy criteria.

The DPS staff has also provided technical assistance to the Vermont Attorney General's efforts to support improved efficiency standards for appliances. In recent years there have been federal rulemaking and subsequent court challenges related to higher standards for energy-consuming appliances and equipment. For example, the Attorney General has joined with other states to secure higher standards for air conditioners. Improved federal standards have the capability of ameliorating pressure to build new generating stations and associated transmission-distribution infrastructure.

Act 250 Commissions continue to rely on the DPS staff to evaluate energy features of projects it has under review. Staff analyzes and comments upon about 200 Act 250 projects annually, seeking a consistent energy condition in permits requiring conformance with minimum energy guidelines and installation of beyond-minimum equipment when it makes economic sense. The DPS also encourages Act 250 developers to use the services available through EVT. Over time, the DPS staff have developed collaborative relationships with Vermont's design-construction community in an effort to simplify the permit process while achieving higher levels of energy efficiency.

The DPS works directly and indirectly with EVT and BED staff on energy education, code and efficiency standard development, and related activities integrated with EVT and BED services.

RECOMMENDATIONS

Vermont has created a valuable strategy for capturing energy savings through efficiency and conservation. Much of the work that needs to be done in the future involves evaluating and refining that strategy, in addition to adjusting to changing energy markets. Vermont's electricity strategy should include these steps:

- Vermont should maintain its strategy of capturing energy efficiency savings through an efficiency utility, but should regularly evaluate the effectiveness of EEU programs and make adjustments as warranted by these evaluations.
- Future Stakeholder Participation in Evaluation -- The suggestion that greater public input is needed is well taken and the Department plans to determine and implement an effective public input process for future EEU evaluation plans, evaluations, and in future planning.
- Impact Analysis -- Wherever possible, evaluation of EEU programs will include actual empirical estimates (i.e., impact analysis) of savings levels actually achieved based on billing history and/or analysis of appropriate comparable patterns of consumption.
- Rate Impacts -- Establishing a credible rate impact analysis will help advance and focus debates around the EEU on core issues of program design, equity constraints in the deployment of programs, and overall cost-effectiveness.
- Vermont should study the impact of locational marginal pricing in the regional electricity market, and whether this development will mean that Vermont ratepayers will reap greater benefits if DSM programs focus more heavily on constrained areas.

- Vermont utilities should encourage demand response as means to reduce demand and to decrease costs, particularly in areas where congestion may cause reliability to degrade or increase costs.
- Vermont state government should continue to play a leadership role in pursuing opportunities for energy efficiency and conservation through the Clean State Initiative and the Climate Change Action Plan.
- As Vermont utilities shift from winter to summer peaking systems, utilities should develop strategies for encouraging summer load management through appropriate strategic load management and demand management technologies. Appropriate use of customer price signals, and incentives may be appropriately targeted to foster adoption of appropriate customer strategies and technologies.

CHAPTER 7. The Bulk Power Transmission System and Standard Market Design

INTRODUCTION[1]

The North American electricity system is one of the great engineering achievements of the past 100 years. This electricity infrastructure represents more than $1 trillion (U.S.) in asset value, more than 200,000 miles (320,000 kilometers (km)) of transmission lines operating at 230,000 volts and greater, 950,000 Mega Watts (MW) of generating capability, and nearly 3,500 utility organizations serving well over 100 million customers and 283 million people.

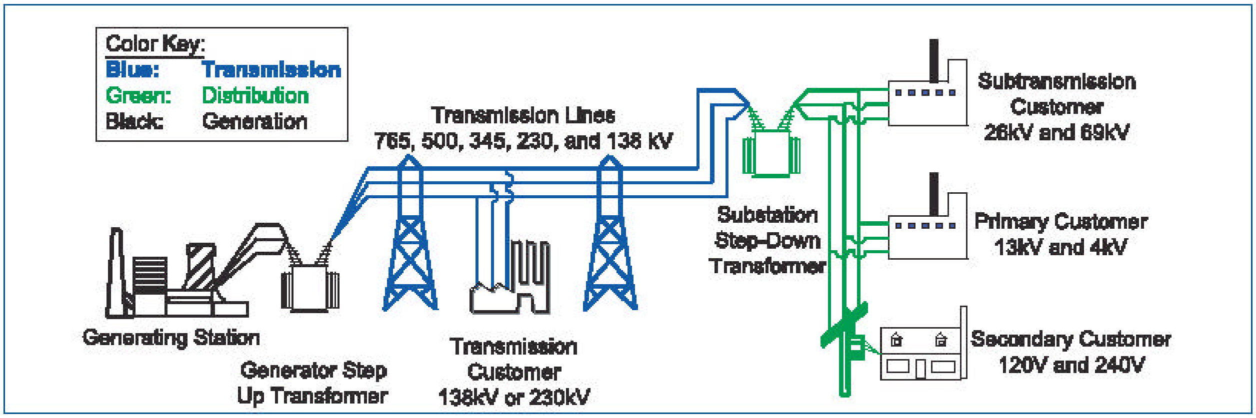
Modern society has come to depend on reliable electricity as an essential resource for national security, health and welfare, communications, finance, transportation, food and water supply, heating, cooling, lighting; computers and electronics; commercial enterprise; and even entertainment and leisure. In short, nearly all aspects of modern life are driven by electricity. Customers have grown to expect that electricity will almost always be available when needed at the flick of a switch. Most customers have also experienced local outages caused by a car hitting a power pole, trees falling on overhead lines, a construction crew accidentally damaging a cable, or a lightning storm. What is not expected is the occurrence of a massive outage on a calm, warm day. Widespread electrical outages, such as the one that occurred on August 14, 2003, are rare, but they can happen if multiple reliability safeguards break down. Such outages, in turn, produce considerable economic losses.

On August 14, 2003, large portions of the Midwest and Northeast U.S. and Ontario, Canada, experienced an electric power blackout. The outage affected an area with an estimated 50 million people and 61,800 MW of electric load in the states of Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, New Jersey and the Canadian province of Ontario. The blackout began a few minutes after 4:00 pm Eastern Daylight Time (16:00 EDT), and power was not restored for four days in some parts of the U.S. Parts of Ontario suffered rolling blackouts for more than a week before full power was restored. Estimates of total costs in the U.S. range between $4 billion and $10 billion (U.S. dollars).[1] In Canada, gross domestic product was down 0.7% in August, there was a net loss of 18.9 million work hours, and manufacturing shipments in Ontario were down $2.3 billion (Canadian dollars).

Providing reliable electricity is an enormously complex technical challenge, even on the most routine of days. It involves real-time assessment, control and coordination of electricity production at thousands of generators, moving electricity across an interconnected network of transmission lines, and ultimately delivering the electricity to millions of customers by means of a distribution network.

[1] Excerpted from: U.S.-Canada Power System Outage Task Force Final Report on the August 14, 2003 Blackout in the U.S. and Canada: Causes and Recommendations April 2004 , pp. 5,6,9

Figure 7-1 Basic Structure of the Electric System



As shown in Figure 7-1, electricity is produced at lower voltages (10,000 to 25,000 volts) at generators from various fuel sources, such as nuclear, coal, oil, natural gas, hydro power, geothermal, photovoltaic, etc. Electricity from generators is "stepped up" to higher voltages for transportation in bulk over transmission lines. Smaller generators may interconnect at lower voltages on smaller transmission lines or even distribution lines – adding to the complexity of the electric system. Operating the transmission lines at high voltage (230,000 to 765,000 volts) reduces the losses of electricity from conductor heating and allows power to be shipped economically over long distances. Transmission lines are interconnected at switching stations and substations to form a network of lines and stations called a power "grid." Electricity flows through the interconnected network of transmission lines from the generators to the loads in accordance with the laws of physics-along "paths of least resistance," in much the same way that water flows through a network of canals. When the power arrives near a load center, it is "stepped down" to lower voltages for distribution to customers. The bulk power system is predominantly an Alternating Current (AC) system, as opposed to a Direct Current (DC) system, because of the ease and low cost with which voltages in AC systems can be converted from one level to another. Some larger industrial and commercial customers take service at intermediate voltage levels (12,000 to 115,000 volts), but most residential customers take their electrical service at 240 volts.[2]

While the power system in North America is commonly referred to as "the grid," there are actually three distinct power grids or "interconnections". The Eastern Interconnection includes the eastern two-thirds of the continental U.S. and Canada from Saskatchewan east to the Maritime Provinces. The Western Interconnection includes the western third of the continental U.S. (excluding Alaska), the Canadian provinces of Alberta and British Columbia, and a portion of Baja California Norte, Mexico. The third interconnection comprises most of the state of Texas. The three interconnections are electrically independent from each other except for a few small DC ties that link them. Within each interconnection, electricity is produced the instant it is used, and flows over virtually all transmission lines from generators to loads.

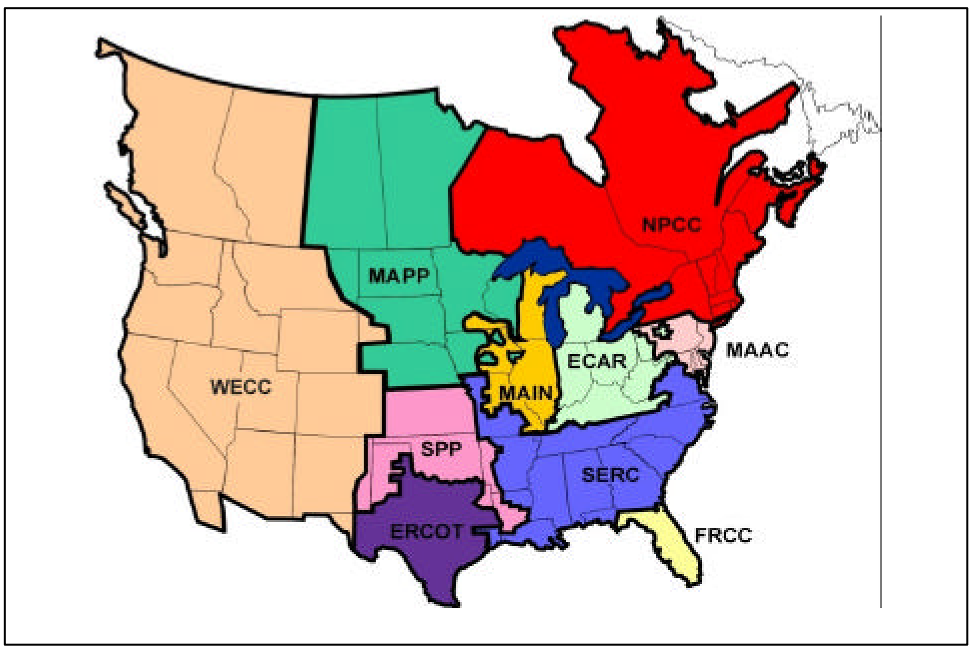
[2] The 240 volt supply provided by the utility is then tapped at the customer's service panel to provide 120 volt service to small appliances, lights and other devices.

GENERAL ISSUES SURROUNDING NEW TRANSMISSION INVESTMENT

THE NEED FOR A RELIABLE DELIVERY SYSTEM

The northeast blackout of 1964 prompted the electric utility industry in 1965 to create the North American Electric Reliability Council (NERC), an independent, non-profit organization that is responsible for the reliability of the majority of interconnected bulk power systems in the U.S., Canada, and a portion of Mexico. There are several individual councils within the NERC that are responsible for the reliability of smaller regions within the U.S. and Canada. The Northeast Power Coordinating Council (NPCC), formed, in 1966, includes New England, New York, Ontario, Quebec, and the Maritime provinces. Figure 7.2 outlines each of the reliability councils, including the NPCC.

Figure 7-2 North American Electric Reliability Council (NERC)



Source: NERC Web Site - Maps

The NERC continues to receive considerable attention and scrutiny due to the August 14, 2003 blackout. Legislators, the media, and consumer groups have questioned how a widespread outage could occur, given NERC's charter and reliability guidelines that are designed to prevent such an event. Notably, several of the conditions and shortcomings that caused the 1964 Northeast blackout, the New York City blackout in 1977 and more recently, brownouts and rotating blackouts in California still appear to be problematic.[3]

Some believe additional federal rules are needed to prevent another blackout; suggesting new regulations instituted by the Federal Energy Regulatory Commission (FERC) may have contributed to

[3] Inadequate communications protocols, operator error and problematic protective relaying systems were cited by NERC as contributing factors.

a power delivery system that has weakened over time. A recently defeated federal Energy Bill included legislation that would have provided the NERC with greater enforcement powers. The bill also would have given greater authority to the FERC along with the NERC to ensure the safe and reliable operation of the bulk power grids within the U.S.

Although the original energy bill failed, subsequent revisions continue to address electric reliability and it is anticipated that the NERC prospectively will have greater enforcement powers, including mandatory rules to require reliability councils, power pools or utilities to construct new generation or transmission if bulk system reliability is deemed to be in jeopardy. The regional transmission organization, Regional Transmission Organization in New England (RTO-NE) that the FERC conditionally approved includes terms that effectively will force transmission owners to construct new facilities if reliability is jeopardized. Regional Transmission Operator proponents and filing documents assure that new rules would not override environmental and siting regulations now administered by individual states.[4]

THE JOINT U.S. AND CANADIAN TASK FORCE REPORT ON THE AUGUST 2004 BLACKOUT

In April 2004, a joint U.S. and Canadian task force issued a report that outlined the causes underlying the August 2003 blackout.[5] The report, ordered by President George W. Bush and then-Canadian Prime Minister Jean Chretien, and undertaken under the direction of U.S. Secretary of Energy, Spencer Abraham and Canadian Minister of Natural Resources, Herb Dhaliwal, also included recommendations to reduce the likelihood and scope of a similar event in the future. The Task Force concluded that the outage could have been prevented if power system operators had followed documented procedures and that immediate actions are needed to ensure reliability. Key findings include:

- Numerous factors contributed to the outage, including several violations of NERC standards; these causes were grouped into the following four categories:

  "Group 1: FirstEnergy (FE) and ECAR failed to assess and understand the inadequacies of FE's system, particularly with respect to voltage instability and the vulnerability of the Cleveland-Akron area, and FE did not operate its system with appropriate voltage criteria and remedial measures."
  "Group 2: Inadequate situational awareness at FE. They did not recognize or understand the deteriorating condition of its system."
  "Group 3: FE failed to manage adequately tree growth in its transmission rights-of-way."
  "Group 4: Failure of the interconnected grid's reliability organizations to provide effective real-time diagnostic support."

[4] An entity that seeks to construct new transmission lines in Vermont – mostly those 30 kV or above - must first obtain a Certificate of Public Good (CPG) under 30 V.S.A. Section 248. To obtain a CPG, the entity, usually an electric utility, must file such a request before the Vermont Public Service Board (PSB), which makes a determination based on evidence submitted by the applicant and other parties, including the Department of Public Service (DPS) and other state agencies, as to whether the proposed facilities promote the Public Good. Notably, Section 248 supercedes other state regulations such as Act 250, although applicants must satisfy criterion similar to those contained in Act 250.
[5] U.S.-Canada Power System Outage Task Force, August 14th blackout: Causes and Recommendations.

- The task force emphasized that the causes cited above did not occur randomly as “they reflect long-standing institutional failures and weaknesses that need to be understood and corrected in order to maintain reliability.”

The report included 46 recommendations to remedy the specific causes cited above and to address institutional deficiencies. Three of these recommendations may have a profound impact on Vermont transmission planning activities and regulatory criteria.

Recommendation 1: Make reliability standards mandatory and enforceable, with penalties for noncompliance.

Much like the 1964 Blackout was a watershed event that created the NERC, so the 2003 Blackout may be the trigger that makes reliability standards mandatory. This recommendation was emphasized throughout the report and includes standards for system design and operations. The monetary component for noncompliance likely would be imposed on ISO-NE (soon –to be RTO-NE). Vermont’s share likely would be its load ratio share of about 4%, unless the problem was caused by Vermont, which then would have to pay a greater share. Perhaps more significant is the imposition of reliability standards, which suggest Vermont’s transmission system would have to comply with the NERC and the NPCC contingency criteria. The implication is that upgrades such as the Northwest Reliability Project (NRP) could be deemed as a required upgrade, which raises questions as to how such requirements are to be reconciled with the Vermont Public Service Board’s (PSB) authority to approve or deny transmission upgrades under V.S.A. Section 248. The FERC currently has jurisdictional authority on terms of service and rates for wholesale transmission, but traditionally has not had the power to authorize or require the construction of facilities needed to meet reliability standards.

Recommendation 4: Clarify that prudent expenditures and investments for bulk system reliability (including investments in new technologies) will be recoverable through transmission rates.

As noted in Recommendation 1, the FERC has jurisdictional authority over wholesale transmission rates. The state of Vermont, through the DPS and other agencies, can intervene in tariff and rate filings. While this recommendation would not likely usurp the right to intervene, it suggests the FERC would approve most, if not all requests for rate recovery on projects and new technologies that are deemed prudent. It is not clear what might constitute a prudent investment; however, an applicant that offers a demonstrable argument that the investment(s) are needed to meet the NERC or regional reliability standards may be more likely to receive a favorable decision from the FERC. These costs, if approved, would flow through to retail ratepayers. The Northwest Reliability Project (NRP) is one example of a project that the FERC likely would deem to be needed for bulk system reliability.

Recommendation 9: Integrate a “reliability impact” consideration into the regulatory decision-making process.

The regulatory decision making process cited in Recommendation 9 suggests that the FERC should expand or modify the criteria it employs to approve tariff rates or conditions. Further, as noted in other sections, the FERC has stated it will be more likely to approve projects that have been recommended and filed by an independent regional transmission operator or organization, particularly if needed for reliability. While none of the recommendations directly indicate the FERC or other federal agencies (such as the Department of Energy) would seek greater jurisdictional authority over what traditionally has been under state purview, the emphasis on reliability and the FERC's oversight role suggests these issues may lead to greater federal involvement in transmission siting and construction filings, such as the CPG process under V.S.A. Section 248 in Vermont.

KEY POLICY ISSUES

Owners of Vermont's transmission system, the PSB, the DPS, and other affected stakeholders must continue to address key issues that will impact the performance and cost of providing service to Vermont ratepayers. Transmission assets and attendant rules have received significant attention from federal and state regulators over the past decade, as adequate transmission is key to ensuring power resources are readily available to Vermont's electricity consumers at the lowest possible cost. An inadequate transmission system can degrade reliability and performance, and increase costs where constraints inhibit the flow of power from lower cost resources to load centers. Vermont's transmission system is an integral part of the power delivery network in New England, which in the past decade has undergone significant changes in the pricing and provision of transmission service. There are major regional initiatives that are proposed or underway which will influence planning methods and decisions for selecting new transmission and supply resources in Vermont. This Plan addresses Vermont's bulk power delivery system in the context of these structural changes.

Key policy issues addressed in this Chapter include:

- An assessment of the Vermont transmission infrastructure
- The impact of Standard Market Design (SMD) and related federal initiatives
- Locational Marginal Pricing (LMP) and its impact on the cost of capacity
- The New England Independent System Operator's (ISO-NE) rules
- The formation of RTO-NE
- Regional transmission planning and its impact on Vermont's power delivery system
- Importation of Hydro Quebec (HQ) Power and Alternate Transmission Paths
- Transmission Seams Resolution (New England and Adjacent States)
- Power system reliability and performance, and expansion options
- Interconnection standards and distributed generation
- Electro Magnetic Fields (EMF)

STRUCTURAL CHANGES

The FERC has been at the forefront of promoting reforms based on competitive market principles. The Energy Policy Act of 1992 (EPAct) provided the FERC with the authority to institute broad-based reforms on wholesale power sales, pricing, and delivery regulations. These reforms have dramatically altered delivery, planning, and pricing methods jurisdictional utilities now employ to provide transmission service. The market has evolved from one characterized by vertically-integrated service providers, to one where generation has been largely deregulated, accomplished in part, via FERC-mandated third-party open access to transmission lines.

New rules under the FERC Orders 888 and 889 in 1996 led to dramatic structural changes in wholesale delivery services and have been the catalyst behind the development of a robust wholesale generating market, with the goal that competitive forces will ultimately provide the impetus for transmission infrastructure upgrades and new generation. With the issuance of its Standard Market Design (SMD) White Paper in 2002, the FERC sought to introduce a standardized set of rules and design principles to provide greater certainty to market participants. The New England Power Pool (NEPOOL) has instituted many of the proposed market reforms described in the White Paper and the FERC Order 2000; their impact on Vermont is described in this Plan.

Not surprisingly, the transition to a deregulated wholesale generation market and open access has created numerous trade-offs and challenges. Foremost among these is the lack of sufficient transmission capacity to accommodate certain wholesale market transactions, particularly when supply resources are remote from load centers. These distant sales at times strain the ability of transmission systems to reliably and economically deliver the power. Related changes and reforms instituted by NEPOOL and ISO-NE also will impact the Vermont transmission system in terms of how new rules have or will apply, including location-based pricing. Further, recent FERC approval for a RTO in New England will have a direct bearing on transmission functionality, planning and system expansion.

The transition to restructured wholesale markets and retail competition has created unintended consequences with respect to reliability and price. California's attempt to fully deregulate the electricity market has been viewed by many as an abject failure, with price hikes, supply shortages, and incidents of market manipulation by unscrupulous traders. Some states have witnessed a reasonably favorable transition to deregulation of retail electricity service – Texas and Pennsylvania often are mentioned.

The recent significant increase in wholesale market prices are attributable, in part, to the significant movement toward reliance on natural gas combined cycle generation. The dramatic shift toward gas combined cycle followed the 1996 change in market design.[6] States like Vermont that delayed movement toward retail choice may be better insulated from the current volatility and rising wholesale prices in the New England market since Vermont utilities continue to depend on pre-existing long term power contracts and sources established or built under arrangements largely prior to the onset of the new wholesale markets. Recent blackouts have heightened public concern regarding power system adequacy and reliability. The August 14, 2003 Northeast blackout has led to calls for reforms, including mandatory reliability rules and penalties for transmission providers. As noted above, such reforms are now the subject of federal legislative proposals.

THE NEW ENGLAND BULK POWER SYSTEM AND MARKET RULES

NEPOOL

The NEPOOL was formed in 1971 to coordinate and direct the operation of the interconnected generation and transmission system in New England. The role and composition of NEPOOL has

[6] As noted, wholesale generation and transmission markets are regulated by FERC and are not affected by state legislative initiatives regarding retail electricity service and rates.

changed dramatically since the issuance of the 1994 Electric Plan. Previously, all operating, planning and administration functions were performed by NEPOOL members. In 1997, many of these functions were assumed by ISO-NE, which was formed to independently administer pool rules and centrally operate the interconnected bulk power system. NEPOOL is now a voluntary association of about 200 members (or Participants).[7] The Participants Committee is the primary stakeholder group, comprised of five sectors representing generators, transmission owners, suppliers, consumer-owned utilities, and end-users.[8]

RESTATED NEPOOL AGREEMENT & MARKET RULES AND PROCEDURES

The relationship among NEPOOL participants is governed by operating rules documented in the Restated NEPOOL Agreement (RNA). This contract describes the rules underlying the operation and administration of wholesale energy and capacity markets in New England by ISO-NE, including power sales transactions under SMD. The RNA also includes the Open Access Transmission Tariff (OATT), which sets forth the terms and prices for transmission service provided to NEPOOL utilities, third-party generators and other entities seeking transmission access. The OATT governs lines rated 69kV and above that support transactions and external transfers under what is commonly referred to as Pool Transmission Facilities (PTF).

Included in NEPOOL's RNA and Market Rule 1 are many of the rules that govern wholesale transactions under SMD. Market Rule 1 sets forth the procedures to be followed for implementing the Multi-Settlement System (MSS), Locational Marginal Pricing (LMP), Installed Capacity (ICAP), and Financial Transmission Rights (FTR), and other financial procedures related to SMD. The methods used to implement and enforce the new rules and procedures are outlined in related NEPOOL Manuals. Standard Market Design and related initiatives are described in greater detail herein and in other sections of the Plan.

THE ISO-NE

Following the deregulation of segments of the wholesale market by FERC in 1996, NEPOOL created ISO-NE in 1997 to function as the independent system operator for New England.[9] ISO-NE is a non-profit, non-stock organization governed by a Board of Directors whose members do not have a financial stake in the New England electricity market.[10] It maintains an "arms length" business relationship with NEPOOL and has two essential responsibilities: administering a fair and efficient wholesale generation and transmission marketplace, and performing the day-to-day operation of the bulk power system in New England. The current interim NEPOOL ISO Agreement governing ISO-NE activities terminates with the effective date of the RTO approved by FERC.[11] The operational date for RTO is February 1, 2005.

The interim agreement provides ISO-NE the authority to adopt rules as needed to operate the bulk

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[7] There is a minimum $5,000 fee to become a NEPOOL Participant.

[8] Vermont Participants include VELCO and the Vermont Public Power Supply Authority (VPPSA). VELCO represents the operating companies as a single entity in NEPOOL. Note that suppliers also may be the load-serving entity.

[9] Other ISO's in the U.S. include the New York ISO, PJM interconnection, the Midwest ISO, the California ISO, and Electric Reliability Council of Texas (ERCOT).

[10] The ten member Board of Directors, elected by NEPOOL, includes a former Chairperson of the Vermont PSB and Commissioner of the PSD.

[11] ISO-NE, in its October 31, 2003 RTO filing before FERC requests early termination of the interim agreement with NEPOOL, and elimination of the Restated NEPOOL Agreement.

power system and residual wholesale market.[12] It also sets forth procedures, standards and policies for system reliability, market rules, and dispute resolution, including the ability to unilaterally enact new or change existing rules during emergencies to ensure the reliability of the interconnected system is not compromised. ISO-NE conducts operating and planning studies to meet its reliability obligation; these include regional transmission expansion studies.

ISO-NE administers NEPOOL's OATT in addition to its responsibility for short-term bulk power system reliability. The OATT includes assets classified as PTF, whereas each transmission entity, including VELCO and the larger Vermont utilities, maintains a separate OATT for non-PTF local service. Currently, rates for service over each transmission owner's facilities, PTF and non-PTF includes a return based on a utility-specific return on equity and weighted cost of capital.

In May 1999, ISO-NE enacted new rules based on FERC competitive market principles to support an open market for energy transactions. Short-term energy transactions were valued at a single pool-wide clearing price. In late 2002, FERC approved ISO-NE's proposal to implement SMD, which expanded the single pool-wide clearing price to one based on LMP rules. Currently LMP's are calculated for 900 nodes within New England and energy transacted at eight zones. ISO-NE submitted a compliance filing with FERC on March 1, 2004 that expands LMP to include location-based capacity rules (LICAP). Each of these initiatives and rules is described within this Plan.

REGIONAL TRANSMISSION OPERATOR (RTO-NE)

In 2000, FERC issued Order 2000, which required jurisdictional utilities to develop proposals to form either Regional Transmission Organizations (RTO) or Independent System Operators (ISO).[13] Most major utilities in the U.S. have joined or committed to join an ISO or RTO. Accordingly, FERC has refocused its attention on RTO/ISO pricing rules as opposed to participation requirements. In the Northeast, three ISOs already have been established and have developed and administer market-based rules: PJM (Pennsylvania, New Jersey and Maryland), NYISO (New York Independent System Operator) and ISO-NE (May 1997). Figure 7.3 illustrates existing and proposed RTO's and ISO's in the U.S. and Canada.

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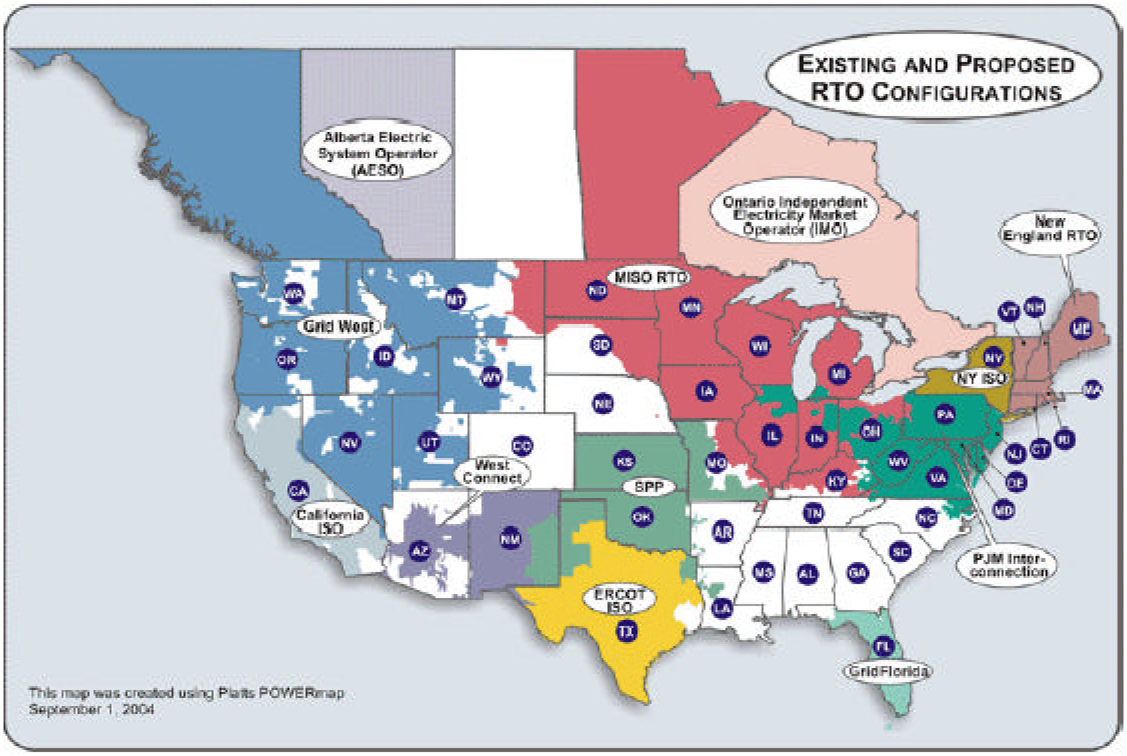
[12] In its September 29, 2003 Order, FERC has authorized an extension of the interim agreement expiration between NEPOOL and ISO-NE from June 2002 to December 2004, but cautioned the extension would not obviate compliance under RTO Order 2000.

[13] RTO's differ from ISO's as the latter assumes operational control such as central generation dispatch and to facilitate third party transactions. RTO's include several models, such as a single business entity that would independently own all transmission assets in a region, to arrangements whereby utilities would jointly plan and construct transmission assets. Compliance with Order 2000 could be met via the formation of RTO's or Compliant ISO's.

Figure 7-3



On October 31, 2003 ISO-NE and the New England Transmission Owners (TO's) requested FERC approval for the formation of a regional transmission organization in New England (RTO-NE).[14] On March 28, 2004 the FERC conditionally approved the RTO. Under current rules, which will remain in effect pending appeals and responses to the FERC conditions, transmission owners of PTF are the service providers under the NEPOOL OATT, while ISO-NE independently administers the OATT. Operation date for RTO-NE is February 1, 2005. As proposed, the RTO will direct the transmission operations for New England as provided by the TOA and assume the operational responsibilities and market administration now performed by ISO-NE. It will continue to operate as a non-profit, non-stock corporation, but with greater autonomy to enforce rules that promote SMD principles and ensure reliability. To comply with the FERC Order 2000, the RTO, rather than NEPOOL participants, will retain authority on terms of service and rates, with participant stakeholders placed in an advisory role. NEPOOL, in its current structure, effectively will cease to exist, although many of the rules contained in the RNA and Market Rule 1 will in large part be incorporated into RTO rules, OATT and attendant TOA.

RTO-NE will unify the ISO-NE and the transmission owner's OATT's into a single tariff that incorporates existing local point-to-point and network service rate schedules. The RTO will have authority under Section 205 to modify non-rate conditions and terms of service including review of

[14] The New England transmission owners include Central Maine Power, Bangor Hydro, Northeast Utilities, NSTAR, United Illuminating and VELCO. The original filing was made under FERC Docket Nos. RT04-2-000, ER04-116-000, and a supplemental Section 205 rate filing on November 4, 2003 under Dockets ER04-157-000 and ER04-157-001. The supplemental filing included Green Mountain Power (GMP) and Central Vermont Public Service (CVPS) as joint applicants.

individual TO rate filings to ensure reliability and market efficiency goals are addressed.[15] The TO's will retain Section 205 filing rights for local service and rates, although RTO would have the authority to modify rates and rate design if TO's are unwilling or unable to implement upgrades needed for reliability or to support market transactions. The regional tariff provides "one-stop shopping" for merchant generators seeking interconnection, and prohibits multiple access fees to transmission customers, consistent with FERC's RTO rules.

The FERC conditionally approved the filing despite strong opposition from NEPOOL participants. Documents filed with the FERC report that 80% of NEPOOL participants oppose the RTO as originally filed; the 20% who fully supported the original filing are the transmission owners. Notably, the New England Conference of Public Utility Commissioners (NECPUC) conditionally supported the joint ISO/TO filing, including the right to make the filing, with several key exceptions and clarifications, in a letter submitted to the FERC on January 8, 2004.[16]

The FERC agreed that the RTO will set clearer price signals, reduce transmission seams via enhanced regional planning and include rules under which transmission owners would be contractually obligated under a TOA to expand or upgrade transmission facilities for reliability or to improve market efficiency. It includes joint regional planning and pricing initiatives with New York that would provide for a "virtual regional dispatch" (by first quarter 2005) and elimination of inter-pool export charges (phased out over five years), thereby eliminating rate "pancaking" and expanding the northeast wholesale market scope from 25,000 MW to 60,000 MW without modifying dispatch control areas.[17] The transition from an ISO to an RTO is portrayed as reasonably straightforward as many of the rules administered by the ISO would remain essentially intact, such as LMP-based mechanisms for congestion management. The filing also adopts much of the language currently embodied in the Restated NEPOOL Agreement and Market Rule 1.

Opponents of the RTO suggest the new rules will significantly increase cost without offsetting benefits, and biases the planning process to favor transmission solutions. Several states (collectively, the "New England Advocates") asserted that the ISO already functions as an RTO and is Order No. 2000 compliant; perhaps of greater concern is that the RTO will inappropriately shift greater authority to the transmission owners, particularly with regard to rates.[18]

In approving the RTO, FERC rejected claims by interveners that ISO-NE and the transmission owners

[15] Transmission service rendered under the RTO tariff would include current PTF bulk facilities, but exclude all non-PTF facilities such as Highgate HVDC and Phase I/II, the CSC merchant transmission facility or local non-PTF low voltage systems. FERC rejected requests from some parties that FERC require the roll-in of certain Canadian facilities into the new RTO-administered OATT.

[16] Michael Dworkin, Chairman of the Vermont PSB, signed and presented the letter to FERC on behalf of NECPUC.

[17] On July 31, 2003, ISO-NE and the New York Independent System Operator (NY-ISO) entered into an Interregional Coordination and Seams Resolution Agreement (ICA) to work jointly to improve integrated system planning between their respective organizations. The ICA includes several of the key features of the RTO filing including virtual dispatch and phase-out of export charges, which would help achieve price convergence between the respective ISOs.

[18] The complaint was jointly submitted to FERC by the Attorney General of the Commonwealth of Massachusetts, the Connecticut Office of Consumer, Counsel, the Maine Public Advocate and the New Hampshire Office of Consumer Advocate; December 8, 2003. The NEPOOL Participants Committee filed a motion with FERC on December 2, 2003 protesting the formation of the RTO.

do not have the authority to request RTO status under Section 205 of the Federal Power Act.[19] They also produced a study that concluded retail costs would increase by $40 million to $70 million annually.[20] The increase is mostly due to Return on Equity (ROE) adders that the FERC indicated it would provide to entities that agreed to form RTO's and construct new transmission facilities.[21]

The FERC approved a 50 basis point adder to return on equity for Regional Network Service (RNS), indicating the formation of the RTO warranted the adder similar to prior RTO filings, but rejected applying the adder on Local Service under the RTO OATT. The FERC set for hearing requests for a 12.8 base ROE applied to existing assets and a 100 basis point adder for transmission assets installed after January 2004 under the RNS; however, the FERC rejected outright the same adders for Local Service. The FERC also conditioned its approval on the submission of a seams resolution agreement with the NYISO.

The FERC reviewed the filing in the context of Order 2000 and found the joint filing, with conditions, is in compliance with the Commission's rules for RTO's.[22] The RTO will provide greater separation of market participants' influences on governance issues. The greater independence of the RTO must be balanced with the increased role between the RTO and transmission owners on planning and pricing decisions, issues the DPS will closely monitor. The FERC, in its conditional approval of the RTO, cautioned that changes in RTO rules and requests for changes in rates or terms of service must meet "reasonable and justifiable" criterion, with significant opportunity for state and other stakeholder participation in the review process.

THE VERMONT TRANSMISSION SYSTEM

DESCRIPTION AND OVERVIEW

The Vermont transmission system includes facilities rated 34.5kV to 345kV AC and a single DC line that operates at 450kV. Generally, facilities rated 69kV and below are classified as subtransmission and are primarily owned by the local distribution utilities, mostly GMP and CVPS.[23] Many subtransmission lines are operated radially, whereas the vast majority of lines rated 115kV and above operate as bulk transmission facilities and are configured in a looped or network arrangement.[24]

[19] The New England Advocates and other New England Participants argued that only the NEPOOL Participants Committee could petition FERC to terminate the existing NEPOOL Agreement.
[20] FERC's Transmission Pricing Policy: New England Cost Impacts, Synapse Energy Economics, Inc. (September 29, 2003)
[21] The RTO transmission owners would receive a 0.5% ROE premium for existing assets to 2012, and another 1% ROE premium for new transmission facilities.
[22] *Regional Transmission Organizations*, FERC Order No. 2000
[23] Some 69kV lines located in the lower Connecticut River Valley are owned and operated by the U.S. Generating Company, and are used to deliver output fromhydroelectric facilities at Harriman, Searsburg and several plants located on the Connecticut River. CVPS owns the section of the 69kV line between Bennington and Searsburg, which is contiguous to the 69kV line that connects to the Harriman and Searsburg hydro units.
[24] In New England and other regions, bulk transmission facilities sometimes are defined as lines rated 230kV and above that comprise the primary backbone system for bulk power delivery and regional reliability. In New England, lines rated 115kV and above that operate in a network arrangement are eligible for designation as a PTF, including many in Vermont. For purposes of Section 6 and consistency with other terms described therein, facilities rated 115kV and above and that operating in a network arrangement and hence are eligible for PTF status will be defined as bulk transmission.

Almost all facilities rated 115kV and above, except for the 450kV DC line, are owned and operated by the VELCO.[25] Most VELCO lines are overhead; the most notable exceptions are the two-mile underground and 0.6-mile submarine cables that cross Lake Champlain between Milton and South Hero, and South Hero and Plattsburgh, respectively. Figure 7-8 is an illustration of the Vermont and New England bulk transmission system, including external ties to adjacent states and Canada.

Table 7.1 summarizes transmission lines by voltage level and line miles. Vermont's high voltage transmission system (lines rated 115kV and above) is about 540 line miles. The remaining 950 miles of subtransmission lines are rated 34.5kV, 44kV and 69kV; mostly owned by GMP and CVPS.[26] These amounts exclude transmission lines owned by non-Vermont companies. The 540 miles of high voltage lines in Vermont is about 7%of the 8,000 miles of line in New England. This ratio exceeds the Vermont to New England pool load ratio, which is slightly above 4 percent. Upon completion of the Northwest Reliability Project (described later), if approved by the PSB, this ratio is not likely to materially change over the next five to ten years.

Table 7-1 Composition Of Vermont's High Voltage Transmission System

Voltage	Line Miles	Percent of Total
345kV	86.9	5.8%
230kV	32.5	2.2%
115kV	423.3	28.4%
< 115kV	946.7	63.6%
Total	**1489.4**	**100.0%**

Transmission losses typically comprise about 30% to 40%of total system losses, which for many utilities range from 8% to 12% of load at the time of peak demand. Energy losses are lower on a percentile basis, as losses decrease proportionally by the square of the load. Table 7.2 presents demand and energy losses for bulk transmission and subtransmission as percent of total system losses. Table 7.2 also provides a relative measure of the value of losses. Assuming avoided losses are valued at $50/MWh (composite value for both demand and energy), a 5% reduction in high voltage transmission losses (approximately three MW and 8000 MWh) equates to $400,000 annually.

Table 7-2 Typical Transmission Losses

[25] VELCO, whose services, tariffs and rates are under federal jurisdiction (FERC), is wholly owned by the Vermont operating utilities, whose ownership shares are in an amount roughly equal to their respective load share of total Vermont load (additional details are presented in Section 2).

[26] The FERC has adopted a 7-Step test to classify lines as transmission or distribution. Lines that are radial, at lower voltage, with uni-directional power flows often are classified as distribution. Under this test, some of the low voltage radial subtransmission, and possibly some radial high voltage lines, could be reclassified as distribution. Some U.S. utilities have relied on the FERC 7-Step test to reclassify certain transmission lines, which places them under state, rather than federal jurisdiction. The FERC has provided utilities significant latitude when seeking to reclassify these facilities, which serves to reduce transmission rates and therefore, reduce the cost of third-party wholesale transactions.

Voltage Class	Peak Transmission Losses (MW)	Energy Losses (MWh)	Percent of Total Transmission Losses
115kV & Above	63	159,160	69%
34.5kV to 69kV	26	72,029	31%
Total Losses	**89**	**231,189**	**100%**

Vermont's high voltage transmission system rated 115kV and above, was first constructed in the 1950's to deliver power from hydroelectric projects in New York to Vermont's operating utilities. Higher voltage lines rated 230kV and 345kV were constructed in the early 1970s to deliver power from Vermont Yankee (VY) and to increase import capability from the eastern part of the state and New Hampshire. Since the early 1970's, relatively few new transmission lines have been constructed. The most notable exceptions include the 52-mile Vermont section of the 450kV DC line between Des Canton, Quebec and Comerford, New Hampshire,[27] and the 32.5-mile 120kV line built by Citizens Utilities in 1992 and 1993 between Derby Line and Richford, Vermont. In 1985, the Vermont utilities constructed a 225MW High Voltage Direct Current (HVDC) converter station in Highgate and a new 7.5-mile line to interconnect with HQ lines at the Canadian border.[28] VELCO recently purchased from Citizens the 32.5-mile 120kV line, related substation assets and a 23-mile 120kV line built in 1960. These assets were purchased in conjunction with the Northern Loop Project (NLP) recently approved by the PSB.

CURRENT MAJOR PROJECTS

NORTHERN LOOP PROJECT (NLP)

In Docket 6792, the PSB approved certain upgrades collectively described as the NLP. The NLP includes substation upgrades, 115kV line additions, and a reconfiguration of the 115kV system in northern Vermont. The primary purpose of the NLP is to enhance reliability in northern Vermont and to provide greater operating flexibility. Construction is scheduled to begin in Summer 2004 and all facilities are scheduled to be fully operational by year-end 2005.

Key elements of the project include:

- Construction of six miles of new 115kV transmission line along an existing right-of-way between Irasburg and Newport;

[27] The Vermont utilities created a separate entity, the Vermont Electric Transmission Company (VETCO), to purchase the Vermont share of the 450kV DC line. VETCO owns 52 miles of HVDC lines.. Vermont was provided rights to Hydro Quebec (HQ) purchase above the state's load ratio as a condition of the use of rights-of-way located in Vermont. The line is rated to deliver up to 2,000 MW, but operates at lower levels due to stability limits in the U.S.

[28] The Highgate station converts AC power from HQ to DC, then back to AC on the VELCO system. The back-to-back conversion of power is necessary because the U.S. and HQ power systems operate asynchronously and hence, cannot operate in parallel. Similar converter stations are located in Des Canton, Quebec, Comerford, New Hampshire, (690 MW) and Sandy Pond, Massachusetts (2,000 MW).

- Reconfiguration and the addition of new 115kV breakers and capacitor banks at VEC's and VELCO's Highgate Substations[29];
- Installation of a new substation breaker and related upgrades at VELCO's St. Johnsbury substation;
- Installation of 115kV breakers and related upgrades at VELCO's Irasburg substation; and
- Reconfiguration of VEC's high voltage transmission system to include a new 120kV HQ source at Highgate (in addition to an existing 120kV HQ source at Derby Line)

The PSB issued a CPG to VELCO authorizing the above-described construction together with the sale of certain 46kV and 115kV transmission assets and rights-of-way by VELCO from Citizens ($7.3 million net of depreciation). The total cost for the NLP, excluding the purchase of Citizens' transmission assets is estimated at $22 million, of which $14 million is eligible for classification as PTF. Under PTF, Vermont will pay approximately five percent, or $700,000 of the $14 million, as their costs are allocated according to load ratio share. Vermont's peak load is approximately 1000 MW; the most recent NEPOOL peak was approximately 25,500 MW.

The NLP creates a new tie to relieve congested facilities in northwest Vermont. Closing the 6-mile transmission tie between existing 115kV lines in Newport and Irasburg will permit flow-through between Highgate and St. Johnsbury. Lines are currently operated radially. The reconfiguration provides a source at Highgate to back up Citizens' 115kV feed from HQ at Derby.

NORTHWEST RELIABILITY PROJECT (NRP)

Northwest Vermont has been identified as one of two areas in New England in greatest need of reliability reinforcements. ISO-NE, in its 2003 Regional Transmission Expansion Plan offered the following to emphasize the need for reinforcement.

> *"The Northwest Vermont area faces severe reliability problems due to weak interconnections with the bulk transmission system and a lack of any new generating resources or distributed resources in the region. The load pocket in the rapidly growing Northwest Vermont/Burlington area remains subject to service interruption due to the relative scarcity of local generation, weak interconnections with the rest of the New England transmission system, and potentially problematic interconnections to other control areas, ties that are essential to reliably serving Northwest Vermont. While the situation is critical today, it is expected to worsen considerably with continued load growth."*

In June 2003, VELCO and GMP requested approval from the PSB under 30 V.S.A. Section 248 for upgrades collectively described as the NRP. The PSB is presently considering the proposal in Docket 6860. VELCO asserts that the proposed project is needed to reinforce the power delivery system in northwest Vermont, via the construction of new and upgraded 115kV and 345kV transmission lines and substations, to satisfy reliability criteria up to a state load level of approximately 1,200 MW (load projected for 2011) and that the NRP would provide sufficient transmission available to reliably deliver output from new generation to load centers thereby avoiding congestion charges.

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[29] Prior to the NLP filing, Citizens and VELCO each owned substation equipment at their respective Highgate substations. These substations will be combined as one in conjunction with the upgrade and reconfiguration of substation facilities at each location. VELCO has since purchased all land and substation equipment previously owned by Citizens at this site.

Key elements of the proposed NRP project include:

- Constructing of 35.5 miles of new 345kV transmission along an existing 115kV right-of-way between West Rutland and New Haven;
- Constructing of 27.1 miles of new 115kV transmission, mostly along an existing 46kV and 34.5kV right-of-way between New Haven and South Burlington;
- Reconductoring 5.6 miles of an existing 115kV transmission line between Williamstown and Barre;
- Upgrading substations in West Rutland, Blissville, Middlebury, New Haven, Ferrisburg, Shelburne, South Burlington and Williamstown (Granite);
- Upgrading and relocating substations in Vergennes and Charlotte; and
- Installing new Phase Angle Regulators in Blissville, Sandbar and Williamstown (Granite).

Most of the proposed NRP improvements and additions have been classified as PTF, making them eligible for regionalized cost support under the Restated NEPOOL Agreement and NEPOOL OATT.[30]

TRANSMISSION SYSTEM INVESTMENT

ROLE OF VELCO AND TRANSMISSION EXPANSION PLANNING

Any period during which major new transmission construction is not needed provides the State, VELCO, the operating companies, and other stakeholders with an opportunity to carefully consider how the state can best meet its long-term power delivery needs. We are mindful of the direction ISO-NE is following with respect to its Regional Transmission Expansion Planning (RTEP) process and Wholesale Markets Plan, which promote market-based solutions prior to utility-supported options and greater regional planning (beyond New England). The market-based options include conservation and demand side management, independently owned generation, and merchant transmission. The DPS supports similar planning methods for Vermont to ensure resource parity when supply and demand-side options are considered and evaluated. With this Plan we propose a similar planning process for VELCO.

To date the PSB has not required VELCO to develop an integrated resource plan or long-range integrated solutions to their resource needs. The Department is not now proposing that VELCO prepare an IRP. As Vermont's statewide transmission company VELCO is, however, best positioned to identify statewide least cost solutions to potential transmission reliability concerns that extend beyond the reach of any single distribution company. We therefore propose that VELCO propose a long range network expansion plan, and an associated planning process, in collaboration with its owners to ensure that the least cost solutions, whether market-based or delivered through the existing utility-based structures are delivered.

Another key planning issue Vermont will need to address is how best to leverage its interconnections to HQ. As noted elsewhere in the Plan, several of the existing contracts with HQ terminate after 2012 and resource planners will need to address whether new contract opportunities that may arise. There are direct ties to HQ at Highgate and Derby Line, in addition to Vermont's capacity entitlements under

[30] NEPOOL approved eligibility of NRP PTF funding in early 2003.

Phase I and II. Given Vermont's proximity and existing interconnections, the state could seek to maximize its ability to leverage these interconnections to Vermont's benefit. Notably, there are opportunities to leverage existing transmission interconnections and corridors to increase imports directly to Vermont. Increasing the import capability of the 120kV interconnection at Derby Line, now owned by VELCO, has been studied or identified in the past, including increasing block loading capability or installing a new back to back converter in this area. With the completion of the Northern Loop, approximately one-half of the load now delivered at Derby Line will instead be delivered by HQ at Highgate, thereby freeing up some capacity on existing lines. The potential benefits of new converter facilities also could be examined in the context of long-term plans as well.[31]

Vermont's current contracts with HQ also have important implications for the reliability of Vermont's transmission system. Presently, system reliability at high load periods requires the flow of at least 200 MW from HQ over the Highgate interface into northwest Vermont. If these current contracts and the associated flows through Highgate are lost, a need would be created for either additional transmission investment, significant new generation in the northwest portion of the state, or specific wheeling and contractual arrangements designed to keep this interface active.

ISO-NE REGIONAL TRANSMISSION EXPANSION PLAN (RTEP)

To improve regional planning for transmission needed to support market-based wholesale transactions and reliability, ISO-NE since 2000 has conducted comprehensive studies of the regional transmission grid.[32] Annually, ISO-NE issues a report titled the RTEP that summarizes these studies.[33] ISO-NE conducts these studies in cooperation with the Transmission Expansion Advisory Committee (TEAC), a voluntary group comprised of ISO-NE members, utilities, reliability councils representatives, and merchant plant owners, and other stakeholders. Participation is open to all interested parties.[34]

The RTEP studies address the resource adequacy of the six-state region on an integrated basis over ten years; it generally does not assess local transmission requirements. Resource adequacy is planned and designed to meet NEPOOL's "one day in ten year" Loss of Load Expectation (LOLE) reliability criterion, which requires generation resources of a sufficient amount such that the likelihood of customers being disconnected due to the inadequacy of generation is no more than one day in ten years.

To achieve resource adequacy, RTEP first seeks market-based solutions, including investment in generation (including distributed generation), demand response programs, and conservation or merchant transmission. Current and proposed NEPOOL rules are designed to create an incentive for transmission owners and third parties to invest in solutions in areas experiencing constraints. If the

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[31] The ability of HQ to increase export capacity by constructing new line in southern Quebec may be hampered by public opposition in the province, which HQ has witnessed for other non-export-related transmission projects.

[32] The term "regional" or "region" in the context of this plan represents the six-state New England power grid and external ties to other states or provinces.

[33] Under the proposed regional transmission authority, the RTEP would be renamed the Regional System Plan (RSP) and the TEAC renamed the Planning Advisory Committee (PAC) to reflect a greater emphasis on system expansion issues, including generation, demand response and conservation, as opposed to an emphasis on transmission expansion alone.

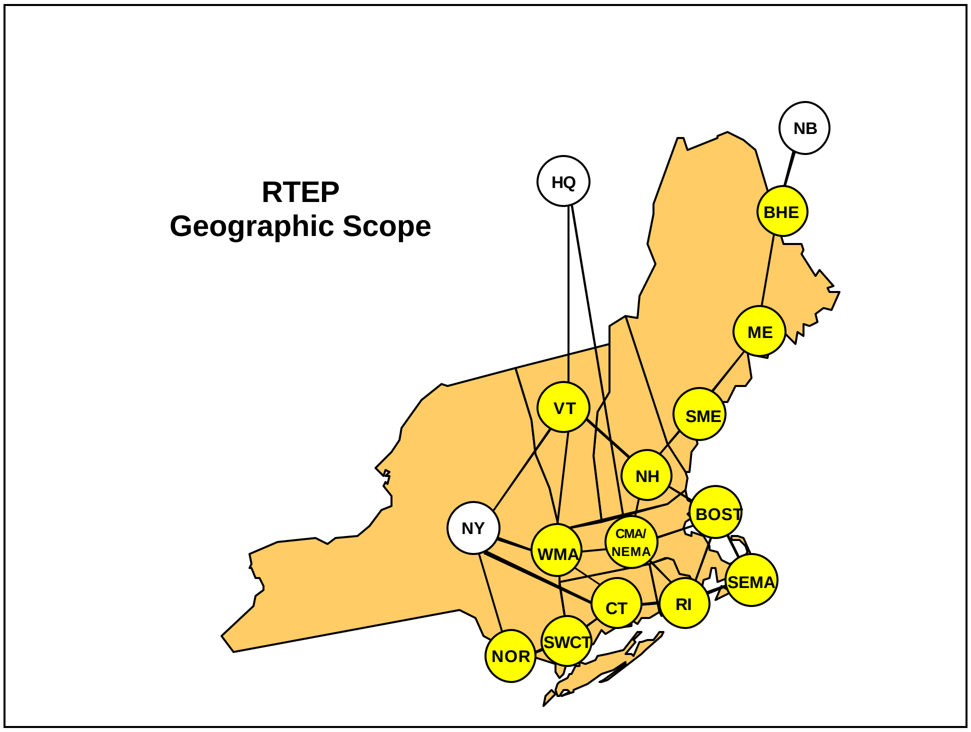
[34] Vermont is usually represented by VELCO transmission planning staff.

market does not or is unable to respond, the RTEP provides regulated transmission solutions.[35] Given that industry reforms are relatively new and new rules are pending, competitive markets have yet to fully mature, therefore regulated solutions are likely to continue in New England and Vermont.[36]

Figure 7.4 illustrates the geographic areas that ISO-NE includes in the regional transmission model, which roughly corresponds to areas where transmission interface constraints exist or to match SMD pricing zones. There are 13 regions in the model, and three key external ties to New Brunswick, Quebec and New York. The RTEP studies focus solely on transmission performance and reliability between the sub-areas interfaces, and not intra-areas within each area. Transmission studies addressing constraints or local reliability issues are left to the individual transmission owners to address.

[35] ISO-NE has implemented other measures to meet short-term resource adequacy, such as PUSH rules to incent generation owners to defer unit retirements and recent "GAP" auctions in resource-constrained areas such as Southwest Connecticut.
[36] One notable exception is the Cross Sound Cable (CSC), a merchant transmission line that links southern New England to New York markets in Long Island.

Figure 7-4 RTEP Geographic Scope



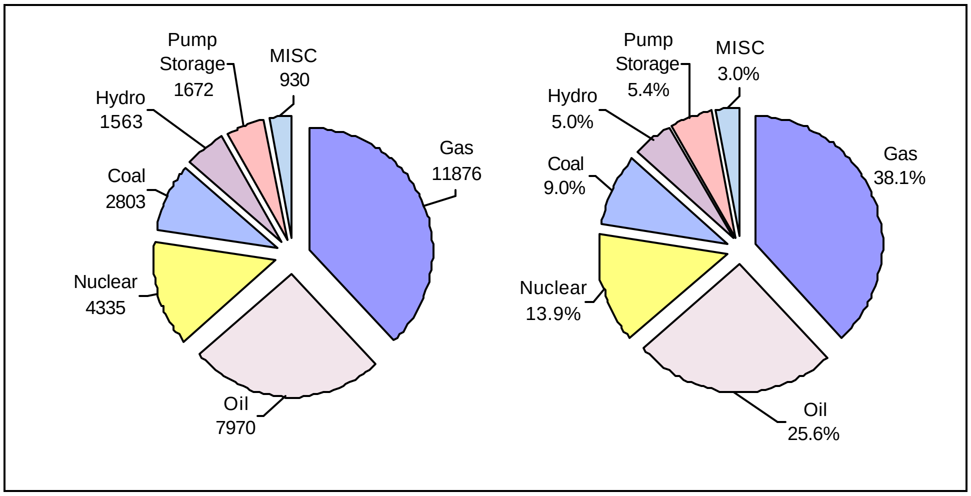
BHE -	Northeast Maine	**WMA -**	Western Massachusetts
ME -	Western & Central Maine/ Saco Valley, New Hampshire	**SEMA -**	Southeast Massachusetts/ Newport Rhode Island
SME -	Southeast Maine	**RI -**	Rhode Island/bordering MA
NH -	North, East, & Central New Hampshire/Eastern Vermont & Maine	**CT -**	North and East Connecticut
VT -	Vermont/Southwest New Hampshire	**SWCT -**	South Central Connecticut
BOSTON -	Greater Boston, inc. North Shore	**NOR -**	Norwalk/Stamford, Connecticut
CMA/NEMA -	Central Massachusetts/ Northeast Massachusetts	**NB, HQ and NY -**	Represent the New Brunswick, Hydro Quebec and New York external Control Areas

Source: Figure 3.4, RTEP03 Executive Summary and Overview, November 13, 2003

Since ISO-NE was formed in 1997, about 9,300 MW of new generation capacity, mostly independently owned combined-cycle gas-fired generation, has been interconnected to the New England grid–none of it in Vermont. This capacity represents almost one-third of the generation in New England. The total New England firm capacity is about 31,000, which is about 21% above the historic NEPOOL peak of 25,348 that occurred on August 14, 2002 (The historic Vermont peak is about 1050 or 4% of the pool-wide peak). Figure 7.5 breaks down the New England resource mix by fuel type.

Research reports indicate approximately 96% of the generation added in the U.S. is natural gas-fired combustion turbines or combined-cycle units. Up to 80% of new generation to be added in the U.S. between 2003 and 2025 is expected to utilize natural gas as a primary fuel source. One of the concerns highlighted in the RTEP, and other NEPOOL/ISO reports and documents, is the risk associated with over-reliance on generation using natural gas as a fuel supply. Natural gas shortages caused by severe cold weather, such as those experienced in early 2004, or pipeline supply interruptions, increase the risk of inadequate generation supply despite adequate reserve margins. The issue is compounded for dual-fired generation–natural gas is the primary fuel and oil is secondary–which is unable to shift use from primary to secondary fuels due to environmental restrictions.

Figure 7-5 NEPOOL Installed Capacity by Primary Fuel Type (Summer 2003 MW)



Source: Figure 3.2, RTEP03 Executive Summary and Overview, November 13, 2003

The ISO-NE Board of Directors approved the current Regional Transmission Expansion Plan (RTEP03) in November 2003. The study addressed resource adequacy by sub-area and pool-wide to year 2012. Notably, ISO-NE emphasizes in RTEP03 and documents filed with the FERC that total installed capacity in New England is sufficient to meet load and reserve requirements.[37] However, transmission bottlenecks have created constraints in some sub-areas, which has degraded reliability and led to increased costs in these areas. Accordingly, many of the recommendations contained in RTEP03 focus on relieving interface constraints.

REGIONAL PLANNING INITIATIVES

In its October the FERC filing requesting approval to transition from an independent system operator to a regional transmission organization, ISO-NE included as an attachment, an Interregional Coordination and Seams Reduction Agreement (ICA) that was entered into on July 31, 2003 between ISO-NE and the NY-ISO. The ICA includes specific provisions to enhance inter-pool transactions and price convergence via phase-out of export charges and instituting a “Virtual Dispatch” of their respective bulk power systems, and possibly other regional ISO’s.

The Proposed New England LICAP rule, which was opposed by NECPUC and other parties, is viewed by ISO-NE as an interim mechanism to address long-term resource adequacy. The successor capacity model envisions a multi-region approach. Accordingly, ISO, PJM and NYISO are jointly addressing regional resource adequacy via a process described as the Reliability Assurance Market (RAM). Proposed rules would extend the planning horizon for capacity auctions over several years

[37] ISO-NE reported in its March 1, 2004 filing to FERC for revised ICAP rules that an 18% reserve margin is sufficient to achieve a one day in ten-year Loss-of-Load-Probability (LOLP) target. Adding generation above the 18% reserve margin target does not materially reduce LOLP.

versus the current one-month capacity auction prescribed under existing ISO-NE rules.

The RTO proposal conditionally approved by the FERC includes expanded emphasis on regional planning that further supports broad stakeholder input on expansion proposals and would include state agency participation in regional planning activities. These include input as a stakeholder as outlined in the ICA with the NYISO to address seams issues. Also, Attachment V of the RTO filing includes a Wholesale Markets Plan for 2004 and 2005 that describes proposed changes in SMD pricing mechanisms, including the transition to a Virtual Regional Dispatch with New York by Spring 2006. The most likely avenue for state input on regional planning may be via state government initiatives. On September 8, 2003, the New England Governors Conference endorsed a proposal to form a Regional State Committee (RSC) on Electricity Policy. This would provide advisory input on resource adequacy, and evaluate approaches for interstate transmission planning and siting.

A Regional System Plan (RSP) will replace the RTEP, and the TEAC will be replaced by a Planning Advisory Committee (PAC). The RSP includes broader regional analyses, including Canadian systems that are part of the NPCC. In addition, as noted in this Chapter, the RTO as the successor to ISO-NE has agreed to enter into an ICA with the NYISO to address seams issues, joint regional adequacy planning, elimination of export fees and achieving a virtual regional dispatch.

A key issue raised by interveners, including the DPS, is a perceived bias in favor of transmission solutions at the expense of distributed generation, demand response and market-based options. The FERC addresses this issue by creating a sixth Alternate Resources Sector in the RTO governance structure and by requiring the RTO to incorporate the RSP in the OATT rather than the TOA, and therefore subject to Section 205 and 206 filings if changes are subsequently made, with mandatory opportunity for stakeholder input. The FERC confirmed the RTO's authority to require TO's to build new transmission when reliability is degraded or constrained, with a further caution that it could impose a solution, stating, "if there is no agreement to build a given project, we will require RTO-NE to submit a report to the Commission, which will permit us to determine whether to require an enlargement of facilities under the Federal Power Act (FPA) or take other steps."[38] Further, a TO will not be relieved of its obligation to build based solely on the lack of an affirmative ruling or finding by state agencies or authorities. If denied, the RTO will file a report with the FERC, who then will make a determination regarding next steps as authorized under the FPA.

We anticipate ongoing engagement of these issues by the DPS as a member of the new RSC (see, Chapter 2).

SEAMS RESOLUTION

A critical issue that the FERC has directed ISO-NE to resolve is the presence of seams between New England and adjacent regions or control areas. The presence of seams thwarts economic transactions between electric power grids–and potentially reliability–and thus has been the focus of much attention. The RTO filing includes direct references and attachments that include initiatives to reduce seams, with specific timeframes for implementation. ISO-NE defines seams as:

> "*Seams are barriers and inefficiencies that inhibit the economic transaction of capacity and energy between neighboring wholesale electricity markets, or control areas, as a result of differences in*

[38] Finding 214, p. 66 of the FERC's March 24, 2004 RTO Order. The FERC also ordered the RTO to clarify standards and procedures it would employ in the RSP, including how it would address market-based solutions, cost-effectiveness and treatment of FTR's and ARR's.

market rules and designs, operating and scheduling protocols and other control area practices."

Seams have evolved in large part because different regions and control areas have adopted different rules and procedures to support wholesale electricity transactions. Several steps have been undertaken by ISO-NE to promote reduction of seams between New England, New York, and Canadian provinces. Several of these entities have signed a Memorandum of Understanding (MOU) that identifies seams constraints and potential solutions. Many of these initiatives involve establishing communication and system planning protocols, agreements that permit the mutual exchange of power, and adoption of SMD and FT/DA pricing. The key to reducing seams is to have consistent market rules in place among regions and sufficient transmission capacity in place to allow these exchanges to take place.

We anticipate ongoing engagement of these issues by the DPS as a member of the new NESCOE – the New England State Committee on Electricity.[39]

As part of ISO-NE's RTO filing, the ICA includes specific directives to continue to reduce seam constraints between New England and New York. The Wholesale Markets Plan also addresses the development of Virtual Regional Dispatch (VRD) with New York, which would permit generation in one region to serve load in the other and vice versa. The intent is to increase price convergence between ISO-NE and New York. VRD initiatives are tempered with the provision that joint dispatch would be permitted if reliability is not degraded. The DPS, as a key stakeholder, will seek to monitor and participate in these activities.

POOL TRANSMISSION FACILITIES

Historically, NEPOOL has employed pricing methods that roll in the cost of bulk transmission assets used to accommodate the delivery of power resources. The group of transmission assets eligible for rolled in pricing is commonly referred to as PTF. Currently, eligible facilities include assets rated above 69kV. Eligibility and pricing rules are contained in the RNA. Summary statistics highlighting PTF and non-PTF lines are presented in Table 7.3. Specific transmission lines classifications, existing and proposed, are listed in Exhibit 2.

The list of PTF assets in Vermont will soon be expanded to include portions of the NLP project recently approved by the Vermont PSB. The NRP now pending before the PSB also has been granted PTF status and most of the proposed facilities will be added to the list if it receives a CPG from the PSB.

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[39] See ***http://www.eei.org/meetings/nonav_2004-10-25-tq/ScottBrownRegionalStateCommitteeDiscussionUpdates.ppt,*** Image #4 RSC (see, Chapter 2).

Table 7-3 Vermont Transmission System Statistics

Vermont Transmission System Statistics		
Existing Lines	**Miles**	**Ave. Age (weighted)**
PTF - High Voltage (230kV-345kV)	111.9	30.1
PTF - Low Voltage (115kV)	264.3	44.0
Non-PTF (115kV)	166.5	30.6
Subtotal	**542.7**	**31.9**
Committed and Proposed Lines		
PTF (115kV - 345kV)	69.1	-
Non-PTF (115kV)	0.0	-
Subtotal	**69.1**	-
Total Miles of Line	**611.8**	**31.9**

In December 2003 the FERC approved changes in the RNA regarding PTF eligibility and transmission cost allocation (TCA) rules.[40] Changes approved by the FERC created a default pricing mechanism comprised of three categories: participant funding for transmission projects used to facilitate market transactions, local funding for projects that only provide local benefits,[41] and regional support for projects providing regional benefits. Regional cost support includes the rolled-in cost of facilities that are included in the NEPOOL tariff and paid by network customers.

The FERC approved ISO-NE's filing, noting that the transmission cost allocation rules and RNA Amendments were supported by 78% of NEPOOL participants; however, some participants and stakeholders object to the use of a majority support as a basis for approval. Further, the Maine and Rhode Island public utility commissions, Central Maine Power, and several third-party owners of generation assets in New England opposed the filing, citing the incompatibility of the new rules with the FERC's SMD NOPR and LMP principles, characterizing the TCA as a repackaging of existing rules.[42] These parties view the proposed rules as favoring new transmission over generation investments, along with a disregard for cost causation principles.

Alternative proposals would require beneficiaries of new transmission to pay the cost of upgrades. Nevertheless, The FERC approved the amendments as filed, indicating the regional approach is consistent with Commission policy and rejecting the project beneficiary pricing approach as unreasonably burdensome and unnecessary, in part because the NEPOOL grid is highly integrated and provides "diffuse network benefits." The matter is now under appeal for rehearing by several parties, including Vermont, which has emphasized the proposed amendments do not include an appeals process regarding the approval of new transmission as reliable versus economic upgrades as determined by ISO-NE.

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[40] Order on Proposed Amendments to the NEPOOL Tariff and Restated NEPOOL Agreement, Docket ER03-1141-000.

[41] Notably, local upgrades include exclusion of the incremental cost of underground lines when underground construction is not warranted. Also excluded are generation interconnections and merchant transmission facilities.

[42] The DPS and others filed comments that concluded the TCA could require loads in some sub-regions to pay for economic-related upgrades for which they receive no benefits. The DPS further noted the original TCA language agreed upon by a stakeholder group, which would have required that regional support for economic upgrades would need to provide benefits to all reliability regions, was later modified by a Participants Committee that comprised fewer representatives than the stakeholder group.

STANDARD MARKET DESIGN

BACKGROUND

The passage of the EPAct of 1992 prompted the FERC to fundamentally reform the ways in which wholesale power and energy sales are transacted in the U.S. The primary thrust of the legislation was to encourage the transition to a more competitive wholesale market; accomplished, in part, via the unbundling of wholesale supply and transmission delivery services. In July 1996, the FERC issued Order 888, which directed jurisdictional utilities to file OATT to provide non-discriminatory third-party access to the transmission grid. A related Order, 889, requires utilities to implement real-time open access reporting and information systems (OASIS) to provide third party access to transmission scheduling information and thereby facilitate participation in the wholesale market.

The FERC also established rules for Exempt Wholesale Generators (EWG), which deregulated transactions involving third-party ownership of generation. Currently, most states in New England have ordered utilities to divest their generation assets. Vermont is now the only state in New England that has retained a vertically integrated structure, offering bundled supply and delivery services to retail customers. Some Vermont utilities have transferred power-marketing functions to independent third parties in order to fully separate these activities from transmission services as required by the FERC.

With the advent of open access and rolled-in pricing, transmission owners saw little incentive to build new transmission to accommodate third party transactions. In response, the FERC issued a Notice of Proposed Rulemaking (NOPR) on SMD in July 2002 that promoted the use of location-based pricing and market-based rules to enhance the transmission infrastructure in the U.S.[43]

ISO-NE in mid-2002 filed a proposal with the FERC to adopt pricing reforms based on the FERC's SMD concepts.[44] In September 2002, the FERC approved an ISO-NE proposal to implement SMD[45] where load-serving entities pay for electricity based on the aggregate LMP in their respective zones; generators are paid based on the LMP at the node where they are connected.

SMD IN NEW ENGLAND

On March 1, 2003, ISO-NE implemented SMD rules and procedures. Currently, about 75% of the generation supply in New England is in the form of bilateral contracts or self-supply. The remaining 25% of supply transactions are short-term under SMD. It includes both Day Ahead (DA) and Real Time (RT) transactions, administered by ISO-NE. These new rules significantly revise the ways in which generation is scheduled and transacted in New England. ISO-NE describes SMD and its compliance with the FERC NOPR in the following passage in its Reference Guide to SMD and LMP:[46]

"The goal of SMD is to provide New England a market with fair and understandable rules that

[43] Notice of Proposed Rulemaking, Docket RM01-12-000, issued July 31, 2002.
[44] The description SMD originated from market rules developed by PJM and later adopted by the FERC in developing rules for energy and reserve markets. It has since been adopted by ISO-NE to describe rules applicable to the six-state NEPOOL region.
[45] FERC SMD Order, September 20, 2002.
[46] Section 01–*Standard Market Design Overview*

promote greater economic efficiency and competition, promote power system reliability, and provide reasonable wholesale electricity prices."

Up until May 1999, energy sales were based on a single pool-wide clearing price offered to all participants. This hourly price was equal to the marginal price of generation absent congestion. The cost of congestion was rolled into a pool-wide price adder that was distributed equally among all Load-Serving Entities (LSE); commonly referred to as "uplift." The introduction of SMD in March 2003 unbundled the three price components defined above to reflect price differences caused by congestion. Because of transmission constraints, higher cost or out-of-merit generation must operate during periods of high load or when resources are out of service, giving rise to locational based prices.

Current SMD rules depart from the prior single price model to one that now includes: A multi-settlement system for scheduling and pricing DA and RT energy transactions, and use of LMP for establishing energy prices and managing congestion. The DA can be viewed as short-term, forward-looking electricity trading with RT as a spot market. As noted, energy sales previously were transacted under a single settlement system based on the use of a pool-wide clearing price; ISO-NE now administers two settlements each hour. SMD rules also include FTR as hedging mechanism to minimize the impact of congestion pricing in constrained areas. ARR represents the revenues associated with FTR transactions that are credited to loads and owners of certain transmission facilities in constrained regions.

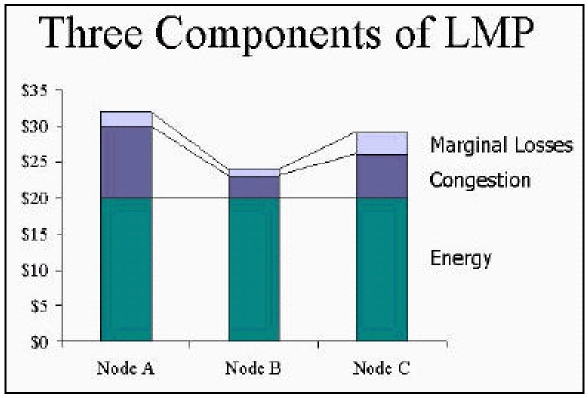
Transactions under DA are financially binding on each party. Use of DA pricing now offers a greater degree of price certainty for LSE's compared to the single RT energy price under the prior pool-wide rate; it provides a hedge to real-time price volatility. DA also provides greater certainty on generator performance. The RT market essentially represents a balancing arrangement that reflects the difference in actual hourly prices energy on committed resources and demand response versus DA bids. If DA forecasts for load and generation were perfectly accurate, DA and RT prices would be the same. However, unexpected loads increases (or decreases), generating unit outages, and other conditions generally cause DA and RT prices to vary.

Prices for DA and RT are based on LMP, which includes the following pricing components:

LMP = Energy Cost + Marginal Losses + Congestion

The energy price is the hourly price of energy assuming no interface constraints on congestion, excluding losses. Marginal losses are calculated for each zone based on the amount of load and mix of generation supplying each node. Congestion represents the additional cost of out-of-merit generation that must be operated to serve load at each node due to transmission constraints. Total LMP is calculate by ISO-NE for each node via use of sophisticated linear programming models that minimizes the total cost to the New England region. The model calculates nodal cost on a continual basis and recognizes interface constraints throughout the region. Figure 7.6 illustrates how prices might vary among nodes where losses differ and where transmission constraints exist.

Figure 7-6



Source: ISO-NE SMD Reference Guide 02 – Locational Marginal Pricing

DA rules differ from RT as transactions represent financial, rather than rights to physical assets. Each day participants issue supply offers and demand bids. For each hour, ISO-NE assembles demand and supply curves based on sellers and buyer bids at each location. The intersection of the curves determines the LMP clearing price for that hour, which represents a binding settlement price regardless of actual unit performance (generators must buy replacement power if their source of supply or generating unit is unavailable or out of service the following day).

Figure 7.7 is a simplified illustration of how the intersection of curves for supply offers and demand bids define the DA LMP for each hour (actual price curve includes many step changes in price as a function of load). Once established, prices paid and amounts charged to entities participating in the DA energy market are based on the hourly LMP. If buyers actual load exceeds amounts purchased in the DA market, they pay actual RT LMP.

Under SMD, ISO-NE calculates LMP at several hundred nodes located throughout New England. Currently, LMP nodal prices are aggregated into eight zones, one for each state, except for Massachusetts, where there are three zones. The price for each zone is based on a load-weighted average of all nodes located within the zone. ISO-NE also prepares a "hub" price, whose cost is the simple average of about 30 non-constrained nodes roughly in the geographic center of New England. The hub price provides a reference average energy price relative to other zones, as these nodes are not subject to congestion. (Brunswick, Quebec, and New York.) The RTEP studies focus solely on transmission performance and reliability between the sub-areas interfaces, and not intra-areas within each area. Transmission studies addressing constraints or local reliability issues are left to the individual transmission owners to address.

Figure 7-7

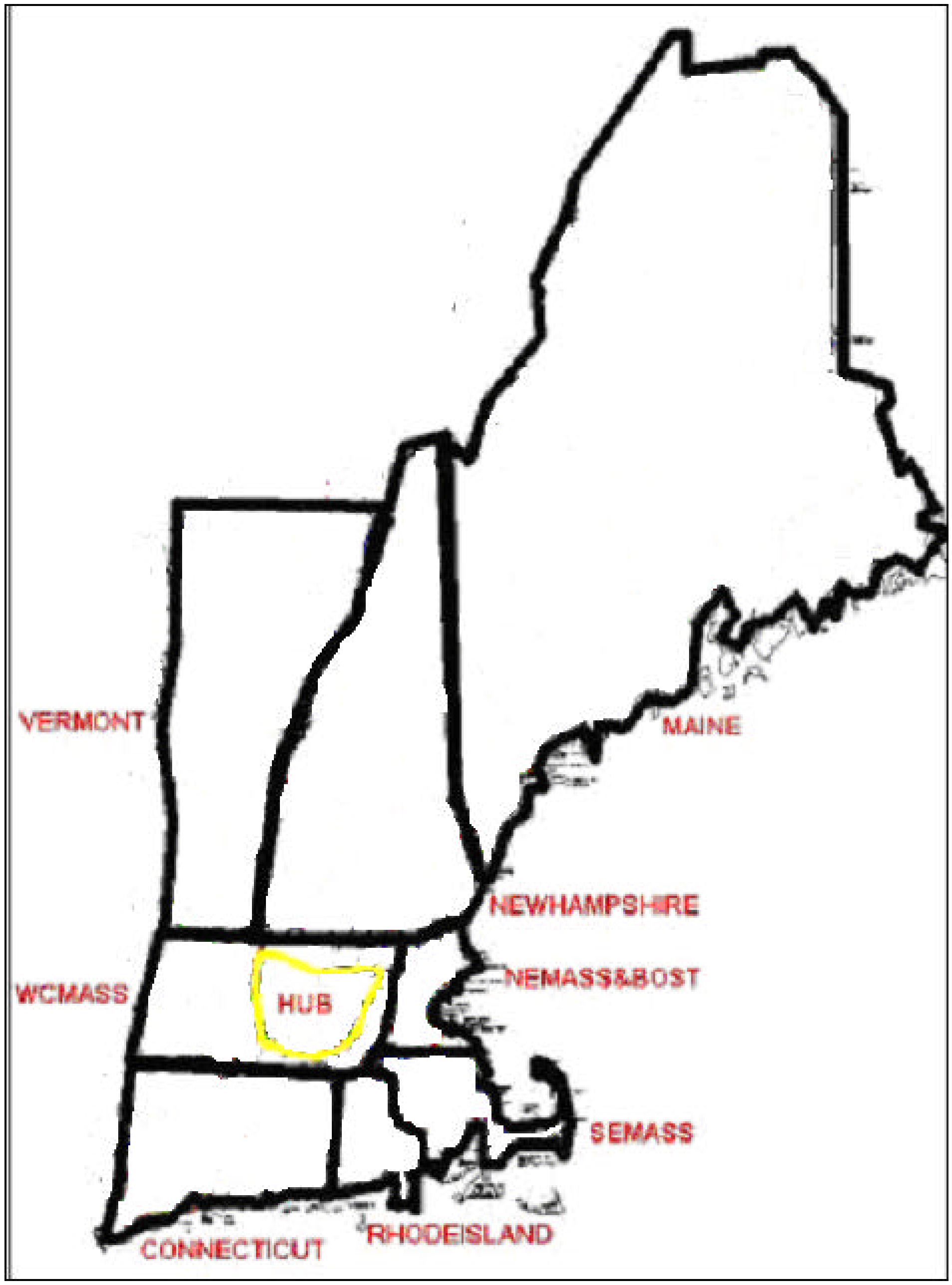
Source: ISO-NE SMD Reference Guide 03 – Multi Settlement System

Figure 7.8 outlines each of the eight pricing zones and the general boundary of the New England hub. Under SMD, the increased cost of operating out-of-merit generation in constrained areas is assigned to the load-serving entities within that area. Stated differently, LMP provides a mechanism under which ISO-NE can identify areas of congestion, and assigns the cost of that congestion to LSE's within their respective areas. The premise underlying the new rules is that LMP provides the appropriate price signals to promote the development and introduction of new supply resources, transmission, or demand response programs in constrained regions.[47] In a perfect market, demand and supply pressures eventually reach a state of equilibrium where transmission interface constraints are eliminated and prices are the same throughout the region (New England).

Some states such as Massachusetts and Connecticut raised objections to SMD and LMP, as each include regions that have constrained transmission interfaces and higher cost generating resources in the constrained regions. The FERC nonetheless approved ISO-NE's proposal and SMD became effective on March 1, 2003.

[47] As explained elsewhere, supply resources include demand-side options such as load control and efficiency alternatives that reduce load during periods of high demand.

Figure 7-8



Source: ISO-NE SMD Reference Guide 02 – Locational Marginal Pricing

FINANCIAL TRANSMISSION RIGHTS (FTR)

FTR's are available to market participants as a hedge to minimize the impact of congestion pricing. They represent a financial entitlement rather than a right to physical assets. FTR's accrue based on the difference between the LMP's that load-serving entities pay versus the amounts paid to generators. They are unidirectional and bidders for FTRs must specify the points of receipt and points of delivery for each FTR bid. The holders of FTR's are paid if power flows from points of receipt to delivery, like LSE's. The holders of FTR's receive a share of the hourly congestion revenues that exist on the NEPOOL transmission systems between points of receipt and delivery. Payments are made to FTR holders if flows are positive between these points. FTR holders are subject to some risk, as they must make payments to the pool if flows are in the opposite direction to those specified in the FTR bid. The difference between the amount loads pay versus the payments generation received in the day-ahead market represent congestion revenues are issued to holders of FTR's. FTR's are sold at auction on a long and short-term basis and can be resold once purchased.

ARRs are the monetary quantities that accrue to those responsible for paying congestion costs. Note that recipients of ARR payments do not necessarily have to participate in the FTR bidding, and can allocate the payments they receive to reduce congestion cost obligations. The allocation of ARR's received from successful bidders of the FTR's are distributed using complex rules that split the revenue according to transmission ownership, the amount of generation located within a load zone and FTR clearing prices. Entities responsible for paying for transmission upgrades are compensated first. Next, LSE's in congested areas are paid a pro rata share of the remaining ARR's.

IMPACT OF SMD IN VERMONT

Vermont has been identified as a constrained zone by ISO-NE. The 2003 RTEP identified Northwestern Vermont as one of the two most critically deficient areas with regard to reliability exposure. Since Vermont is considered a single zone for congestion pricing, increased costs will be borne by all Vermont ratepayers.

Most Vermont utilities continue to meet a substantial portion of capacity obligations via firm contract or owned resources; for example, HQ contract and in-state generation, including up to 10% of supply met by state-mandated purchases from independent supply contracts such as a wood-fired plant in Ryegate and small hydroelectric facilities located throughout Vermont. Changes in regional and New England ICAP rules may provide market participants additional financial incentives to install new generation in constrained areas. Construction of new transmission that relieves constrained interfaces will reduce price increases, particularly if proposed ICAP rules for Designated Constrained Areas (DCA) are authorized by FERC. Accordingly, Vermont policy regarding the bulk transmission infrastructure should be to ensure sufficient cost-effective transmission is installed to ensure Vermont ratepayers are not subject to price increases caused by congestion.

LOCATIONAL MARGINAL PRICING STATISTICS

Table 7.4 presents the range of LMP rates encountered by NEPOOL participants for the first three months after which SMD was implemented in March 2003, second quarter 2003. ISO-NE reports that DA and RT pricing quickly moved to convergence during normal operations after SMD was implemented. Data reported for the remainder of 2003 exhibits similar price convergence. Table 7.4 indicates average DA pricing are about 5% above RT, similar to other northeast markets outside of New England. Also, the average differences in average DA and RT for each load zone is relatively close; less than 10%. However, the range of prices for maximum versus minimum rates was substantial. Maximum RT prices approached $400/MWh while the minimum RT was zero for second quarter 2003. Maximum RT prices have since approached $1,000 per MWh during high summer and winter loads.[48] Price convergence tends to occur during very light loads when generation minimum aggregate output exceeds loads while the maximum pricing reflects cases of extreme congestion coupled with the absence of low-cost supply within zones. Vermont prices are somewhat higher than other New England zones due to higher losses and operation of out-of-merit generation that increased the congestion component of LMP.

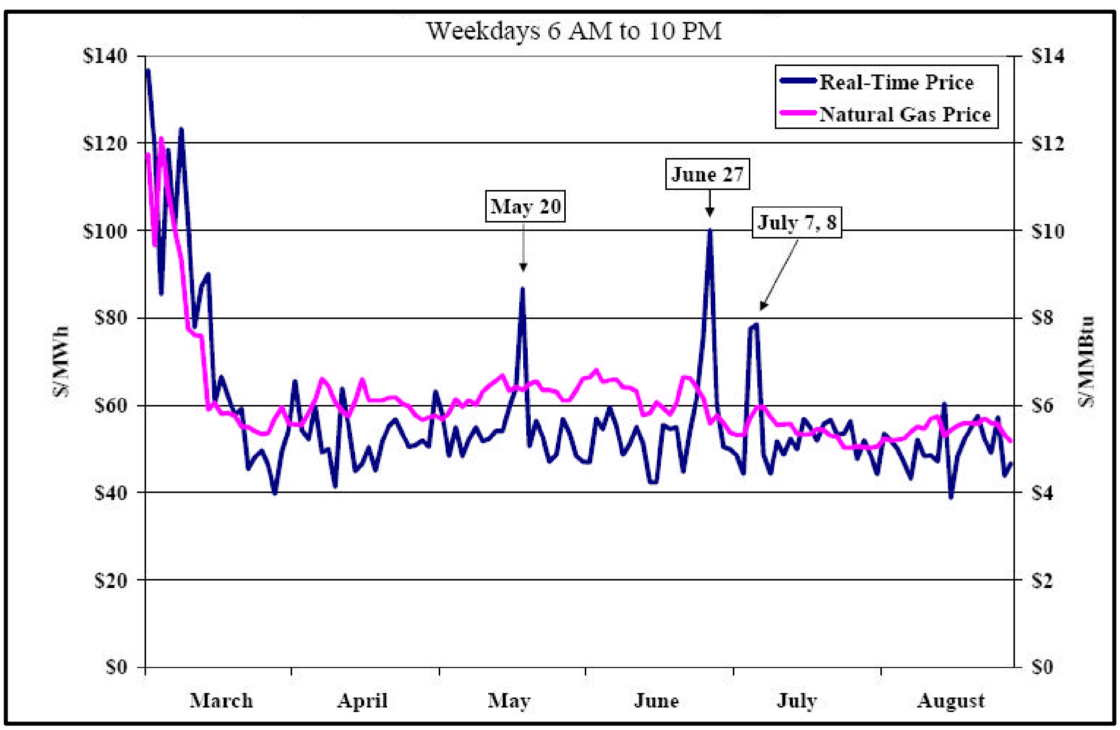
Table 7-4

Table 1 – Summary LMP Statistics for the Quarter, All Hours

Location	Avg DA	Avg RT	Min DA	Min RT	Max DA	Max RT	As % of Hub - DA	As % of Hub - RT	RT as % of DA	DA Std Dev	RT Std Dev	RT SD DA SD
	LMP ($/MWh)											
Internal Hub	$53.30	$52.53	$10.87	$0.00	$148.68	$398.60	100%	100%	99%	$18.98	$25.21	1.33
Maine Load Zone	$49.19	$47.49	$9.99	$0.00	$212.89	$367.81	92%	90%	97%	$21.26	$22.72	1.07
New Hampshire Load Zone	$52.22	$51.11	$10.61	$0.00	$146.17	$389.02	98%	97%	98%	$19.11	$24.11	1.26
Vermont Load Zone	$53.84	$52.55	$2.77	$0.00	$149.30	$388.90	101%	100%	98%	$19.87	$24.99	1.26
Connecticut Load Zone	$53.99	$53.19	$11.02	$0.00	$244.42	$393.44	101%	101%	99%	$20.72	$25.60	1.24
Rhode Island Load Zone	$52.05	$51.75	$10.78	$0.00	$142.42	$394.85	98%	99%	99%	$18.15	$24.75	1.36
SEMASS Load Zone	$52.23	$51.74	$10.71	$0.00	$132.84	$392.85	98%	98%	99%	$18.08	$24.77	1.37
WCMASS Load Zone	$53.30	$52.59	$10.89	$0.00	$148.52	$397.53	100%	100%	99%	$18.89	$25.21	1.33
NEMA/Boston Load Zone	$53.55	$52.15	$10.66	$0.00	$215.00	$397.63	100%	99%	97%	$21.40	$25.66	1.20

Source: ISO New England Q2 Quarterly Market Report, page 5, December 4, 2003

Figure 7-9 Daily Average Real-Time Prices at New England Hub



Source: ISO New England Inc., Docket No. ER02-2330, FERC Compliance Report, Attachment A, p14, March 15, 2004.

Figure 7-9 presents average daily pricing for second quarter 2003 for RT energy and natural gas.

Following implementation of SMD in March 2003, RT prices quickly declined. Further, except for a few summer days RT prices consistently were in the $50/MWh range. Price spikes occurred on three days (and winter 2003/04 as well), generally as a result of large amounts of generation that was out of service, high loads, or both. Notably, the price spikes appeared to be relatively independent of prevailing average natural gas prices.

INSTALLED CAPACITY (ICAP)

Section 8 of Market Rule 1 of the Restated NEPOOL Agreement sets forth the capacity supply obligations of each load serving entity in New England. ISO-NE currently determines the firm capacity requirements for each load zone, including minimum reserves, and then identifies the capacity obligation each load serving member must satisfy to meet its respective monthly obligations. ISO-NE conducts a supply auction monthly to enable load-serving entities to purchase ICAP via transactions with market participants. ISO-NE imposes a monthly deficiency charge if any load-serving entity is unable to meet minimum ICAP following the auction.

ISO-NE has shifted to use of Unforced Capacity (UCAP) to recognize the lower effective capacity of generation. The use of UCAP reflects the probability that some amount of generating capacity will be unavailable to serve load due to forced outages, limited energy output for renewable sources such as hydro, wind, and planned outages. Resources eligible for ICAP include traditional thermal or hydro generation, demand response, and other forms of curtailable load.

In approving ISO-NE's SMD, the FERC recognized that capacity constraints in the region could impair reliability and thwart the development of an economically efficient wholesale generation market. Owners of generation in constrained areas have cut back on maintenance and have proposed to retire older, non-economic generators due to inadequate revenues under SMD. As an interim measure to create an incentive for owners to keep these units available for reliability, NEPOOL petitioned the FERC to approve interim Reliability Must Run (RMR) contracts.

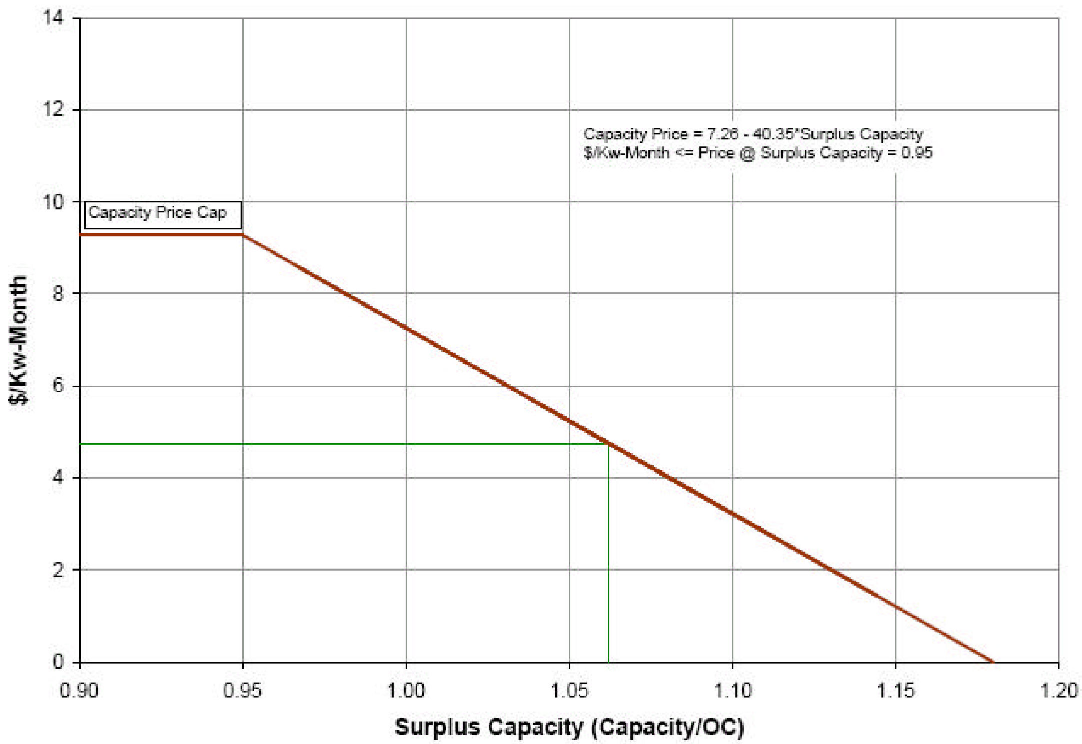
The FERC directed ISO-NE to file an ICAP proposal as a condition of the interim approval of contracts to reduce reliance on RMR's and to expeditiously address resource adequacy in Designated Constrained Areas (DCA) via Resource Adequacy Rules. As an interim measure, the FERC authorized ISO-NE to implement Peaking Unit Safe Harbor (PUSH), which provides for payments to generators operating at 10 % capacity factor or less in 2004 that would provide for reasonable recovery of fixed costs and expenses. PUSH payments are eliminated under the new LICAP rules.

Accordingly, on March 1, 2004 ISO-NE filed revised ICAP rules that would modify payments to generators "so that capacity within DCA's are appropriately compensated for reliability." The new rules are scheduled for implementation in June 1, 2004. Similar to prior SMD interventions, state officials in Massachusetts and Connecticut oppose proposed rules, suggesting they are likely to further raise costs in their respective states. New England regulators, in general, opposed ISO-NE's LICAP proposal, not necessarily because of increased costs, but because the ISO could not show that generators paid under LICAP either were located in congested areas or could run, when needed, for reliability. ISO-NE has proposed to phase-in the rules to minimize the near-term impacts and to allow markets sufficient time to construct new facilities to relieve the constraints.

The inability of SMD rules (prior to the LICAP filing) to recognize the value of generation in constrained areas during periods of moderate congestion was viewed by the FERC as a serious shortcoming. These rules created a price dichotomy that resulted in a vertical price curve that provided for payments approaching deficiency charges in periods where installed capacity was near levels required for reliability and near zero once capacity exceeds requirements; otherwise known as "bi-polar" pricing. The LICAP proposal provides financial incentives for generators by introducing a locational element to capacity pricing and by introducing a non-vertical capacity pricing mechanism.

Figure 7.10 presents the current proposed pricing that will be used to value capacity transactions. The maximum price for capacity is equal to the current Deficiency Price of $6.66/kW-Month at 1.0 capacity margin, adjusted upward to just over $9/kW-Month to reflect historic reserves and infra-marginal revenues. This value declines linearly to zero once the capacity margin in the area reaches 18%. The 18% level was selected as the zero point as it is consistent with the current reserve margin target for New England.[49] Initially, the curve will apply to four ICAP zones or sub-regions in New England: Maine, Connecticut, Northeast Massachusetts, and the "Rest of Pool," which includes Vermont along with all other regions not specified above.[50]

Figure 7-10 Demand Curve Adjusted for Infra-marginal Revenues and Price Cap



Source: ISO-NE March 1, 2003 LICAP filing; Figure 3, pg. 26, and revised NEPOOL Market Rule No. 1, Section 8.

The price curve would be phased in over five years in import-constrained areas such as Connecticut and Northeast Massachusetts, beginning with a $1/kW-Month price cap; the cap will increase annually by $1/kW-Month until year five. Also, capacity payments of $5.50/kW-Month will be applied to

[49]ISO-NE reports that RTEP studies have demonstrated that capacity reserves above 18% provide little additional reliability value to the pool. The current pool margin (2004) is about 23%.

[50] Northeast Massachusetts and Connecticut are defined as import constrained, Maine is defined as export-constrained. External ties also are assigned to sub-regions. The Cross Sound Cable is assigned to Connecticut, the New Brunswick tie to Maine; and HQ Phase I/II, Highgate, and the New York AC ties to the "Rest of Pool."

generators in these two constrained zones with 2003 capacity factors of 15% or less, which allows for elimination of PUSH payments. The new rules also include a hedging mechanism, Capacity Transfer Rights (CTR) that allow market participants to sell or purchase capacity rights between sub-regions.

ISO-NE has proposed a review of LICAP effectiveness via the formation of a Regional Dialog comprised of industry stakeholders and state regulators that would meet periodically over 18 months following implementation of LICAP in June 2004. They propose to identify long-term market solutions or LICAP revisions to address long-term resource adequacy for the entire region. At the end of 18 months, the Regional Dialog would file a plan outlining its recommendations, including modifications to the LICAP rules. Key among these issues is who is responsible for regional capacity procurement and reliability.

The impact of LICAP is likely to be most significant in the two constrained sub-regions in Connecticut and Northeast Massachusetts, with additional annual costs of up to $150 million and $100 million, respectively for locational pricing if the FERC accepts the pricing mechanisms, as filed. Transition support payments to eligible generators in these two areas would annually cost up to $145 million in Connecticut and $20 million in Massachusetts. ISO-NE projects minimal additional cost for the other sub-regions in New England, including Vermont. Vermont is included in the "Rest of Pool" that currently has a composite reserve margin of 44%, well above the proposed Surplus Capacity curve presented in Figure 7.10. So long as margins within other areas of the pool remain above the 18% upper limit, the new rules should not cause increased costs due to locational factors absent changes in LICAP rules.

Similar to the pending RTO filing, some NEPOOL Participants, including VELCO, have petitioned the FERC to reject ISO-NE's LICAP proposal.[51] Objections include:

- The minimum percentage of NEPOOL Participants required to approve the filing was not met (58% approval when two-thirds is required)
- ISO-NE does not have authority under Section 205 to submit the filing
- The pricing method would over-compensate generators - $2.9 million over five years would be paid to generators

ALTERNATIVES TO TRANSMISSION SYSTEM INVESTMENT

In some cases, utilities have tools for dealing with transmission system constraints, in addition to investing in new or upgraded transmission. Demand response has been employed by market participants in the past several years as a cost-effective solution to meet peak demand and to relieve congestion in constrained load zones. It is one of the market-based resource alternatives included in RTEP studies and is given similar weight or emphasis as supply-side options. The program is oriented to medium and large sized businesses. Participants are compensated according to the type of demand response program and notification interval. During Summer 2004, approximately 350 MW of load across New England qualified for demand response status. Demand response is particularly suited in

[51] Other participants opposing ISO-NE's filing include NSTAR, National Grid, the Attorneys General of Massachusetts and Rhode Island, the Massachusetts Department of Energy and Resources, The New Hampshire Office of Consumer Advocate, Associated Industries of Massachusetts, and Strategic Energy LLC. VELCO and Strategic Energy LLC oppose the filing "in part."

constrained areas, where the value assigned to participants is higher. It also has been identified as an appropriate, and perhaps necessary solution to address severe reliability exposure in capacity deficient areas such as southwestern Connecticut. The value of demand response is greatest during periods when congestion or resource constraints cause DA or RT prices to climb steeply, a point acknowledged by FERC in its SMD. An expanded discussion of demand response is found in Chapter 6.

Distributed Generation (DG) is characterized as small, (at least in relation to traditional central station generators) independently owned, and interconnected to lower voltage lines. Providing generation close to load can reduce the need to transport power over distance. More information on distributed generation can be found in the discussion of Distributed Utility Planning (DUP) in Chapter 8.

Energy efficiency can also be used to delay or defer transmission upgrades. Energy efficiency, while a viable option given adequate time, tends to be less viable in the short term. Integration of least-cost services, be they demand-side, generation, and/or transmission services fundamentally begins with the identification of transmission upgrades. Vermont's distribution utilities will need to work with VELCO to devise a strategy for ensuring delivery of least cost solutions in connection with transmission expansion.

ELECTRO MAGNETIC FIELDS (EMF)

Electric and magnetic power frequency fields (EMF) exist wherever there is electric power and include those fields produced by 60 Hertz transmission and distribution power lines, wiring in buildings and homes, and electric appliances. The strength of electric and magnetic power frequency fields decrease as the distance from the source increases.[52] Electric power frequency fields depend on the amount of electric charge or voltage present and are measured in Volts per meter (V/m), or commonly kiloVolts per meter (kV/m). As the voltage of an electric line increases, the strength of the electric power frequency field surrounding that line increases. Average electric power frequency fields in the home range from 0 to 10 V/m or 0.01 kV/m. Magnetic power frequency fields result from the motion of charge (current) and are measured in Gauss (G), or more commonly milliGauss (mG). The strength of the magnetic field surrounding an electric line increases as the current carried on that line increases. Typical magnetic power frequency fields in the home from the electric wiring and various electric appliances average 0.6 mG and range from 0.1 mG to 4 mG over a period of a day. Magnetic power frequency fields close to electric appliances are often much stronger than those from other sources, including power lines. Exposures vary widely from clothes washers (approximately 3 mG at 4 inches) to can openers (approximately 4000 mG at 4 inches).

There are no permanent health effects known to exist from acute or chronic exposure to electric power frequency fields. Electric power frequency fields have very little ability to penetrate through the skin into the human body and are not strong enough to heat tissue or stimulate nerves. At very high field strengths, electric power frequency fields can result in perceptual effects due to the alternating electric charge induced on the surface of the body causing, for example body hair to vibrate. Indirect effects such as micro-shock can occur in strong electric power frequency fields through contact between a person and a conducting object. However, these effects are terminated as soon as the individual moves out of the electric field.

[52] Specifically, the strength of both electric and magnetic power frequency fields are inversely proportional to the square of distance away from the source of the fields. For example, if a person moves from 2 feet to 4 feet away from a source, then the field strength decreases by a factor of 4.

Over the past several decades, concerns have been raised regarding possible adverse health effects associated with magnetic fields and many studies have been conducted to try to identify whether there is a scientific basis for those concerns. The numerous epidemiological and biological studies that have been conducted over the years have not brought us any closer to resolving whether there is an association or dose response relationship between magnetic power frequency fields and health effects. In some epidemiological studies, a weak association between magnetic power frequency fields and childhood leukemia and chronic lymphocytic leukemia in occupationally exposed adults has been found.[53] However, other epidemiological studies report no such associations.[54] The studies have not identified any known biological mechanism for how magnetic fields could cause adverse health effects and no uniform exposure metric has been established for magnetic power frequency fields.

Currently, there are no federal standards for occupational and residential exposure to EMF and no state has adopted health-based standards for EMF exposure. Similarly there are no federal or state standards or guidelines establishing limits on EMF produced by electric appliances. Although some medical device manufacturers do provide some general statements regarding interference with their devices from electric power frequency fields, neither the device manufacturers nor the Federal Drug Administration (FDA) have established standards or guidelines for such devices.

In the absence of federal and state EMF health standards, the Vermont Department of Health (VDH) uses the guidelines established by the International Committee on Non-Ionizing Radiation Protection (ICNIRP) for acute health effects. This recognition comes as a result of the ICNIRP having developed their guidelines based on health effects and as a result of a strenuous internationally based review of the literature. The VDH believes that the ICNIRP guidelines, and subsequent updates, are an appropriate measure at this time, until chronic exposure guidelines are either determined to be necessary or not. If a facility is projected to exceed the ICNIRP guidelines then that facility must be evaluated carefully, taking into consideration possible mitigation techniques.

Overhead power lines expose the public to both electric and magnetic power frequency fields, but at levels well below the ICNIRP guidelines. Although burial of power lines is therefore not necessary for health reasons, if power lines are buried for aesthetic or other reasons, then those lines will expose the public to only the magnetic power frequency fields, due to the shielding by the earth of the electric power frequency fields. Generally, the magnetic power frequency field from an underground power line is less than that from an overhead power line. However, directly over the buried power line the magnetic power frequency field may be higher than directly below an overhead power line. This depends on the type of underground power line used and the installation design, including whether shielding materials are used. The magnetic power frequency field from an underground power line decreases much more rapidly away from it than it does from an overhead power line. The EMF at the edge of the right of way for underground power lines is much less than that from overhead power

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[53] NIEHS: Health effects from exposure to power-line frequency electric and magnetic fields, NIH Publication No 99-4493, 1999.

[54] National Research Council (U.S.): Possible health effects of exposure to residential electric and magnetic fields, National Academy Press, Washington, DC, 1996.

UK Childhood Cancer Study Investigators: Exposure to power-frequency magnetic fields and the risk of childhood cancer, Lancet 354: 1925-1931, 1999.

ML McBride, RP Gallagher et al: Power-frequency electric and magnetic fields and risk of childhood leukemia in Canada, American Journal Epidemiology 149:831-842, 1999

MS Linet et al: Residential exposure to magnetic fields and acute lymphoblastic leukemia in children, New England Journal Medicine, 337:1-7, 1997 lines.

Three broad approaches to this issue have been considered. Vermont's utilities could: 1) take no significant actions and make no investments at this time to limit magnetic power frequency field exposure; 2) adopt a policy of "prudent avoidance" of exposure to magnetic power frequency fields; or 3) adopt aggressive programs to limit magnetic power frequency field exposure.

The first approach is premised on the argument that, because the current body of literature does not establish a direct cause and effect relationship between magnetic power frequency fields and human health, expenditures to limit magnetic power frequency field exposure are unjustified. It is also motivated by the fact that there are numerous hazards in society, which, unlike magnetic power frequency fields, have been unambiguously demonstrated to be harmful. Also, the available evidence indicates that even if the risks of magnetic power frequency fields are shown to be real, the relative risk to society would be small. Hence, expenditures for risk avoidance would be better placed in areas where the risk from hazards is relatively high and well documented, rather than applied towards the relatively small and uncertain risk associated with magnetic power frequency fields. However, the possibility of a health risk from EMF cannot be dismissed entirely because some studies have identified slight but positive associations between EMF exposure and health effects and, therefore, this approach is not recommended.

The second approach, prudent avoidance, means adoption of policies that limit magnetic power frequency field exposure whenever this can be done for a small investment of money and effort. Prudent avoidance argues that a sufficient basis for concern does exist but not enough is presently known to justify large investments for avoiding magnetic power frequency field exposure. Under this approach, large expenditures would not be made until research provides a clearer picture of the existence and magnitude of the risks involved. Given the current state of the science, a policy of prudent avoidance strikes the appropriate balance between avoiding potential harm and the attendant costs and risks.

The third approach is premised on the idea that there is a risk to taking little or no action at this time; the presumed risk is that people could be harmed between now and the time that magnetic power frequency fields are shown to be a significant hazard. Therefore, under this approach, utilities would be required to take the significant steps necessary to mitigate the risks of magnetic power frequency field exposure now, even though subsequent research may show that magnetic power frequency fields pose little or no harm to human health. Aggressive measures taken at this time could be ineffective for two key reasons. First, research could ultimately show that the risks to human health from magnetic power frequency fields are nonexistent or very small. Second, knowledge gained on the dose-response of magnetic power frequency fields could show that the measures that were taken to limit exposure were inappropriate or ineffective. For these reasons, and in light of the insufficiency of the data to demonstrate a direct cause and effect relationship between EMF and health effects, this approach is not recommended.

An EMF policy of prudent avoidance is determined to best strike a reasonable balance between avoiding potential harm and the associated costs and risks. Therefore, Vermont utilities should take steps to lower magnetic power frequency field exposure in cases when this can be done at low or no cost. In most cases, this would apply only to new facilities since modifying old facilities would likely be very costly. Actions that could be considered under the prudent avoidance strategy include the use of low EMF design structures when constructing or rebuilding lines, and siting new or rebuilt lines away from populated areas. Utilities should monitor research on EMF effects and on construction and design alternatives that would reduce exposure. Finally, utilities should provide information on EMF for their customers and the public, including information that would allow concerned individuals to reduce possible risks from exposure on their own. This policy is developed in conjunction with the Vermont Department of Health.

Exhibit 1

Overview of Task Force Recommendations: Titles Only

Group I. Institutional Issues Related to Reliability

1. Make reliability standards mandatory and enforceable, with penalties for noncompliance.
2. Develop a regulator-approved funding mechanism for NERC and the regional reliability councils, to ensure their independence from the parties they oversee.
3. Strengthen the institutional framework for reliability management in North America.
4. Clarify that prudent expenditures and investments for bulk system reliability (including investments in new technologies) will be recoverable through transmission rates.
5. Track implementation of recommended actions to improve reliability.
6. FERC should not approve the operation of new RTOs or ISOs until they have met minimum functional requirements.
7. Require any entity operating as part of the bulk power system to be a member of a regional reliability council if it operates within the council's footprint.
8. Shield operators who initiate load shedding pursuant to approved guidelines from liability or retaliation.
9. Integrate a "reliability impact" consideration into the regulatory decision-making process.
10. Establish an independent source of reliability performance information.
11. Establish requirements for collection and reporting of data needed for post-blackout analyses.
12. Commission an independent study of the relationships among industry restructuring, competition, and reliability.
13. Department of Energy (DOE) should expand its research programs on reliability-related tools and technologies.
14. Establish a standing framework for the conduct of future blackout and disturbance investigations.

Group II. Support and Strengthen NERC's Actions of February 10, 2004

1. Correct the direct causes of the August 14, 2003 blackout.
2. Establish enforceable standards for maintenance of electrical clearances in right-of-way areas.
3. Strengthen the NERC Compliance Enforcement Program.
4. Support and strengthen the NERC's Reliability Readiness Audit Program.
5. Improve near-term and long-term training and certification requirements for operators, reliability coordinators, and operator support staff.
6. Establish clear definitions for normal, alert and emergency operational system conditions.
7. Clarify roles, responsibilities, and authorities of reliability coordinators and control areas under each condition. Make more effective and wider use of system protection measures.
8. Evaluate and adopt better RT tools for operators and reliability coordinators.
9. Strengthen reactive power and voltage control practices in all the NERC regions.
10. Improve quality of system modeling data and data exchange practices.
11. The NERC should reevaluate its existing reliability standards development process and accelerate the adoption of enforceable standards.
12. Tighten communications protocols, especially for communications during alerts and emergencies. Upgrade communication system hardware where appropriate.
13. Develop enforceable standards for transmission line ratings.
14. Require use of time-synchronized data recorders.

15. Evaluate and disseminate lessons learned during system restoration.
16. Clarify criteria for identification of operationally critical facilities, and improve dissemination of updated information on unplanned outages.
17. Clarify that the Transmission Loading Relief (TLR) process should not be used in situations involving an actual violation of an Operating Security Limit. Streamline the TLR process.

Group III. Physical and Cyber Security of North American Bulk Power Systems

1. Implement the NERC IT standards.
2. Develop and deploy IT management procedures.
3. Develop corporate-level IT security governance and strategies.
4. Implement controls to manage system health, network monitoring, and incident management.
5. Initiate U.S.-Canada risk management study.
6. Improve IT forensic and diagnostic capabilit ies.
7. Assess IT risk and vulnerability at scheduled intervals.
8. Develop capability to detect wireless and remote wireline intrusion and surveillance.
9. Control access to operationally sensitive equipment.
10. The NERC should provide guidance on employee background checks.
11. Confirm NERC ES-ISAC as the central point for sharing security information and analysis.
12. Establish clear authority for physical and cyber security.
13. Develop procedures to prevent or mitigate inappropriate disclosure of information.

Group IV. Canadian Nuclear Power Sector

1. The Task Force recommends that the Canadian Nuclear Safety Commission request Ontario Power Generation and Bruce Power to review operating procedures and operator training associated with the use of adjuster rods.
2. The Task Force recommends that the Canadian Nuclear Safety Commission purchase and install backup generation equipment.

Exhibit 2

Vertmont Electric Power Company, Inc
High & Low Voltage Pool Transmission Facilities (PTF and Non-PTF)

LINE DESCRIPTION	KV	CONDUCTOR	UG OH	No. of Circuits	Year Built	Miles of Circuits	Comments
PTF High Voltage Lines							
Coolidge - W. Rutland	115	2-954 ACSR	OH	1	1983	27.4	
Vernon - Northfield (MA)	345	2-927 ACAR	OH	1	1970	0.4	Distance to Mass. border
Vernon - Scobie (NH)	345	2-927 ACAR	OH	1	1970	0.4	Distance to border
Vernon - Coolidge	345	2-927 ACAR	OH	1	1971	51.2	
Granite - Comerford (NH)	230	927 ACAR	OH	1	1971	32.1	
	230	954 ACSR	OH	1	1971	0.4	
				Subtotal - High PTF		**111.9**	
PTF Low Voltage Lines							
Sand Bar - Essex	115	954 ACSR	OH	1	1958	11.2	
Plattsburgh - Sand Bar (VT/NY border)	115	1000 Cable	UG	1	1958	0.6	One spare 500 MCM Cable
	115	954 AA	OH	1	1958	7.0	
	115	1750 MCM pipe cable	UG	1	2001	2.0	
	115	954 ACSR	OH	1	1958	2.3	
Essex - Barre	115	795 ACSR	OH	1	1958	36.3	
Barre - Wilder	115	795 ACSR	OH	1	1958	39.7	
W. Rutland - Whitehall (VT)	115	795 ACSR	OH	1	1958	13.3	Distance to NY border
Coolidge - Ascutney	115	795 ACSR	OH	1	1958	13.0	
Ascutney - North Road (VT)	115	795 ACSR	OH	1	1967	1.2	Distance to NH border
Bennington - Hoosick (VT)	115	795 ACSR	OH	1	1958	6.8	Distance to NY border
Bennington - North Adams (VT)	115	927 ACAR	OH	1	1974	11.0	Distance to Mass. Border
Essex - Middlebury	115	1272 ACSR	OH	1	1954	33.7	
W. Rutland - Middlebury	115	927 ACAR	OH	1	1969	27.8	
Vernon - Keene (VT)	115	927 ACAR	OH	1	1970	0.4	Distance to NH border
Coolidge - Rutland	115	795 ACSR	OH	1	1958	23.8	
Ascutney - Ascutney Tap	115	477 ACSR	OH	1	1958	2.2	
Rutland - W. Rutland	115	795 ACSR	OH	1	1958	5.1	
Georgia - Essex	115	954 ACSR	OH	1	1954	18.1	
Georgia - Sand Bar	115	927 ACAR	OH	1	1974	8.9	
				Subtotal - Low PTF		**264.3**	
Non PTF Lines							
Highgate - Morses Line (HQ - Candaian Bor	345	1272 ACSR	OH	1	1985	7.5	Owned by Highgate HVDC JO's Operated at 120kV
Georgia-Highgate	115	1272 ACSR	OH	1	1958	17.9	
Georgia-Fairfax	115	927 ACAR	OH	1	1972	14.5	
Essex - Burlington (East Avenue)	115	795 ACSR	OH	1	1963	4.8	
Saint Johnsbury to Littleton (NH)	115	927 ACAR	OH	1	1970	9.5	Distance to NH border
Saint Johnsbury to Irasburg	115	927 ACAR	OH	1	1973	36.5	
Bennington to East Arlington	115	795 ACSR	OH	1	1973	5.3	Operated at 46kV
Saint Albans - Saint Albans Tap	115	556 ACSR	OH	1	1958	2.0	
Williston - South Burlington	115	927 ACAR	OH	1	1971	6.2	
Ascutney - Windsor	115	927 ACAR	OH	1	1977	7.0	
Derby Line - Newport	115	795 ACSR	OH	1	1993	6.9	
Newport - Richford	115	1- 556 ACSR, 1-336ACSR	OH	2	1993	25.5	One circuit operated at 46kV
Richford - Highgate	115	556 ACSR	OH	1	1960	23.0	
				Subtotal - Low PTF		**166.5**	
Committed and Proposed Lines							
Newport - Irasburg	345	1272 ACSR	OH	1	2005	6.5	Proposed in-service date
West Rutland - New Haven	345	2-954 ACSR	OH	1	2007	35.5	Proposed in-service date
New Haven to South Burlington	115	1272 ACSR	OH	1	2006	27.1	Conversion of 34.5/46kV lines
				Subtotal - Low PTF		**69.1**	
				Total Miles		**611.8**	

RECOMMENDATIONS:

VELCO

- Under this Plan, the Department proposes that VELCO prepare a long term network expansion plan that will serve to identify long term transmission needs. Such a plan will help assure the least cost delivery of electricity services. The network expansion plan will serve as the foundation from which Vermont's electric distribution companies and VELCO will be asked to acquire or deliver the combination of efficiency services, traditional generation, distributed generation, and/or T&D upgrades necessary to assure service at lowest cost. VELCO should propose a long range network expansion plan, and an associated planning process, in collaboration with its owners to ensure that the least cost solutions, whether market-based or delivered through the existing utility-based structures are delivered.

WHOLESALE MARKET DESIGN

- Vermont regulators and utilities should continue to closely monitor regional wholesale market design to ensure an effective and vibrant market for wholesale power, and participate actively in the RSC to address resource adequacy and fuel diversity issues.
- Vermont regulators and utilities should continue to closely monitor transmission network expansion plans to ensure that network upgrades for which Vermont pays a share, reflect their goals for ensuring the acquisition of all categories of resources at the lowest possible cost.

CHAPTER 8: Resource Planning and Decision-making

INTRODUCTION

Under 30 V.S.A. '218c[1] each regulated electric or gas company is required to prepare and implement a least cost integrated plan for provision of energy services to its Vermont customers. Public Service Board (PSB) Orders, beginning with Docket 5270, define requirements that a utility's complete Integrated Resource Plan (IRP) should meet in order to pass the Department of Public Service (DPS) review and comply with the PSB's approval requirements.[2] The content and organization for a utility's plan should follow the guidelines presented in this Chapter and in Appendix A.

Resource selection does not begin and end with the processes and standards of integrated resource planning. Rather the planning process is an ongoing decision-making process. Under IRP, decision-making must be least cost. However, the framework for determining what is in fact least cost must account for the uncertainties and multiple contingencies. This Chapter and Appendix B highlight a decision-making framework for addressing uncertainties and multiple contingencies.

A particularly challenging area for decision-making is in its applications to developing resource solutions to meeting capacity requirements in local areas. This is known as Distributed Utility (DU) planning. The choices involved can include a variety of resource types, typically comparing local generation and Demand Side Management (DSM) against traditional central station generation and transmission and distribution infrastructure. Once again, this concept fundamentally builds toward identifying resources based on principles of integrated resource planning required by statute.

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[1] 30 V.S.A. § 218c. Least cost integrated planning
(a)(1) A "least cost integrated plan" for a regulated electric or gas utility is a plan for meeting the public's need for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs.
(2) "Comprehensive energy efficiency programs" shall mean a coordinated set of investments or program expenditures made by a regulated electric or gas utility or other entity as approved by the board pursuant to subsection 209(d) of this title to meet the public's need for energy services through efficiency, conservation or load management in all customer classes and areas of opportunity which is designed to acquire the full amount of cost effective savings from such investments or programs.
(b) Each regulated electric or gas company shall prepare and implement a least cost integrated plan for the provision of energy services to its Vermont customers. Proposed plans shall be submitted to the DPS and the PSB. The PSB, after notice and opportunity for hearing, may approve a company's least cost integrated plan if it determines that the company's plan complies with the requirements of subdivision (a)(1) of this section.

[2] The terms Least Cost Integrated Plan (LCIP) and IRP are used synonymously and interchangeably. Natural gas utilities (of which there is only one in Vermont at this time) are also subject to '218c, but not to '202 which establishes this Plan.

INTEGRATED RESOURCE PLANNING GUIDELINES

The objective of the integrated resource planning process is to assure that utility customers are provided with safe and reliable service at the lowest life cycle cost. The cost factors to be considered are both direct dollar costs and those indirect costs that are hard to quantify in dollar terms, such as environmental and societal effects, which are referred to as externalities.

These guidelines establish a consistent format for the development of an IRP, also known as LCIP. The LCIP process and the implementation of each Vermont utility's approved plan are intended to meet the public's need for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs. (30 V.S.A. '218c)

This process is also intended to facilitate information exchange among utilities, regulatory agencies, and the public and culminate in the filing of utility plans that satisfy the standards for the DPS review and PSB approval so that prompt and full implementation can follow.

THE IRP PROCESS

As part of this Plan, the electric utilities should continue to undertake the filing of revisions of their IRPs every three years. The IRP may be subject to the review of the PSB and "approved", otherwise, the filing remains informational. Filing content and standards of documentation, reporting, analysis, and review under the IRP are defined in detail in Appendix A.

Key components of an integrated resource plan are described below. The IRP process includes the establishment of load forecasts, both with and adjusting for the effectiveness of DSM. Uncertainties in the forecast and other elements of the planning environment should be identified, and where possible, characterized and incorporated into the planning process. Both committed and available resources shall be identified. T&D resources should be assessed and plans should be made to ensure efficient and reliable service delivery. Resource selection should reflect an integrated analysis that accounts for uncertainty and contingencies. A complete IRP should include effective strategies for implementing the least cost integrated portfolio identified in the preferred plan. Near term plans require development of actual work plans.

LOAD FORECASTS - The IRP should contain a base case and a forecast of loads taking into consideration the influence of DSM. Vermont distribution utilities and the efficiency utility must work together to ensure that load requirements are properly adjusted for EEU activities, or anticipated activities, in order to help inform other resource and supply decisions of Vermont's utilities. A complete IRP should contain a base case long-term load forecast that ensures adequate resources are available to meet customer needs. Both energy and peak load forecasts should be included. Load forecasts should be broken down to show individual customer classes, own use and losses, with further disaggregation, as possible, to the end use level.

IRP analysis should characterize the principal sources of uncertainty and associated risks to utilities and customers. This analysis should extend beyond uncertainties in load to consider other factors that may present risks to the utility and its customers, such as uncertainties related to projections of fuel prices, loss of major supply sources, and other key forecast drivers and assumptions behind the base case forecast and resource mix. Where analysis reveals unacceptable levels of risk to the utility and its customers with its present portfolio, the utility should characterize avenues for addressing such concerns.

INTEGRATED RESOURCES ASSESSMENT - The IRP should include an inventory of committed and available resources, including supply side resources, T&D efficiency improvements, resources gained through DSM, and other opportunities for better addressing customer needs cost-effectively, such as through rate design.

T&D EFFICIENCY IMPROVEMENT AND ASSESSMENT - Utilities should plan and conduct comprehensive evaluation of options for improving transmission and distribution efficiency. Based on the findings, they should implement a program to assure optimal electrical efficiency. Ample opportunity must be given for meeting needs through appropriate T&D, distributed generation, efficiency services, and/or the delivery of such services through competitive market alternatives.

BULK TRANSMISSION – With respect to bulk transmission, VELCO should support and cooperate with others in undertaking regional T&D optimization and analysis. Where additional transmission capacity is required, the preferred method for increasing transmission capacity should be through the upgrading of existing facilities within existing transmission corridors.

Vermont distribution utilities must work with VELCO to produce a long-range transmission plan that provides timely information so that third parties, including the competitive power market, would have sufficient notice to provide alternative resources such as generation and energy efficiency.

SUBTRANSMISSION – Subtransmission planning should take into account the broader interests than those of individual utilities. Where possible, integrated regional reliability improvements and transmission system optimization should form the basis for basic planning and technical evaluation.

DISTRIBUTION – Duplicate electric facilities are generally not in the public interest. In the process of building, rebuilding, or relocating lines, electric utilities should coordinate with appropriate telephone and cable TV companies during the planning and construction phases to ensure that no permanent duplicate facilities are installed and that the transfer of existing facilities to new or rebuilt poles is done in an expeditious manner.

RELIABILITY – Each utility should, on a continuous basis measure, assess, and enhance the reliability of its power delivery system as described in Appendix A.

VEGETATIVE MANAGEMENT PLAN – All utilities shall establish and describe their current vegetative management plan, and, periodically reevaluate the plan. This is especially important in light of the root cause analysis of the August 14, 2003 blackout where critical transmission lines were tripped by mature tree growth within the utility corridor.

ENVIRONMENTAL IMPACT - The IRP shall demonstrate an understanding, and ideally quantify or demonstrate due consideration, any significant environmental attributes of the resource portfolio, current or planned.

INTEGRATION AND RESOURCE IDENTIFICATION - In developing its portfolio of least cost resources for meeting its long-term energy needs, the utility shall treat all demand and supply side resources consistently and equitably, in accordance with established principles (see Appendix A). The utility should evaluate and identify the least cost portfolio strategy, or preferred plan, taking into account uncertainty and decision analysis.

IMPLEMENTATION - A complete IRP includes effective strategies for implementing the LCIP identified in the preferred plan. For each near term project scheduled to begin implementation within three years, utilities should develop a work plan that includes intermediate targets and milestones that can be monitored and evaluated, identification of utility personnel and anticipated outside vendor responsibilities, and provisions for identifying and adapting to contingencies as they arise.

IRP PROCESS REVIEW

The IRP process has now been in place for more than 14 years. Sufficient time has passed to permit a fresh look at this process and its requirements. The establishment of the efficiency utility should serve to reduce contention in the IRP and review process over the system-wide programs. The principles of least-cost integrated planning appear to be robust. Nevertheless there are reasons for analyzing the success of implementation and associated regulatory review. This appears especially true in relation to use by Vermont's smaller electric utilities and municipal utilities. The process and standards of regulatory review should be refined to ensure that the IRP process is being used effectively and by all Vermont electric utilities. Strategies should be developed collaboratively with Vermont's electric utilities and stakeholders to improve, refine, or even correct aspects of the current process that do not ultimately inure to the benefit of the system and the consumer. Beyond an analysis of the IRP process, it will be critical for the DPS to remain in close contact with utility managers as they contemplate significant resource decisions. As noted throughout the Plan, Vermont will need to address the expiration of the Hydro Quebec (HQ) and Vermont Yankee (VY) supply agreements. Proactive planning is certainly in order, as is effective implementation.

DECISION-MAKING UNDER UNCERTAINTY

Regardless of the energy source, energy investments will continue to be capital intensive and have long-term impacts. Further, continued changes in wholesale power markets and energy price volatility will continue through the planning horizon. Since we cannot eliminate uncertainty that will affect such decisions, the best alternative will be to address that uncertainty and its impacts using a more structured approach. This section highlights one approach for addressing uncertainty and multiple contingencies in the resource selection process. Appendix B presents a more detailed discussion of a decision-making framework known as Decision Analysis (DA) that addresses how best to address the uncertainty that is inherent to long-term resource planning exercises. Decision Analysis may be useful as a stand-alone decision tool or as sensitivity analysis to test the robustness of results reached using more deterministic methodologies. The approach can be used to help inform the decision-making processes or public involvement in resource selection contemplated prior to resource decision-making. The DA process is can be applied equally to the direct or internalized impacts of resource decisions, or it can be applied to outcomes that are more typically external to utility and customer decisions, such as environmental consequences. The interplay between externalities and later impacts that may be later internalized can also be modeled.[3]

[3] Portfolio requirements on renewables, or closed emissions-trading systems, represent an attempt to internalize what might otherwise be considered a classic "externality". As policy-makers develop and consider such tools, it becomes even more important for utilities to consider such influences on their portfolio.

As this Plan has already emphasized, energy markets are fraught with uncertainty. Not only has this contributed much concern about past energy resource decisions, it now colors the way we must approach future energy resource decisions. What is important is to avoid repeating the mistakes of the past.

In the late 1980s, for example, Vermont forecasted rapidly increasing electric costs, stemming from predictions that world oil prices would rise above $100 per barrel. This led State regulators to set the "avoided" cost of power and, hence, the price paid to independent power producers in Vermont, at levels far above today's wholesale prices. As a result, whereas independent generation provides just less than 10% of the State's overall electric supplies, it accounts for almost 20% of the total cost. The HQ contracts that were signed several years later were based, in part, on similar predictions of rapidly escalating world oil prices, and concomitant increases in forecast electric prices. Better decision-making techniques that directly incorporated uncertainty about future energy markets would likely have avoided such forecasting errors.

It is also important to remember that our main focus is on decisions that must be committed to today or in the near term in order to address both current and long-term needs. Future decisions are also important, but grow in importance as the timeframe for making a decision approaches. Most times we do not have to commit today to a potential decision far into the future. For example, utility resource plans often include "generic" resource additions ten or twenty years from now. Such resource "decisions" are irrelevant if they require no action whatsoever today. This does not mean we ignore future needs… to the contrary, it simply means we identify decisions that must be made today, even if such decisions simply preserve options for us in the future. In Chapter 9 we outline possible future energy portfolios for the state. These portfolios are largely illustrative in effect and certainly do not result from the decision practices envisioned here.

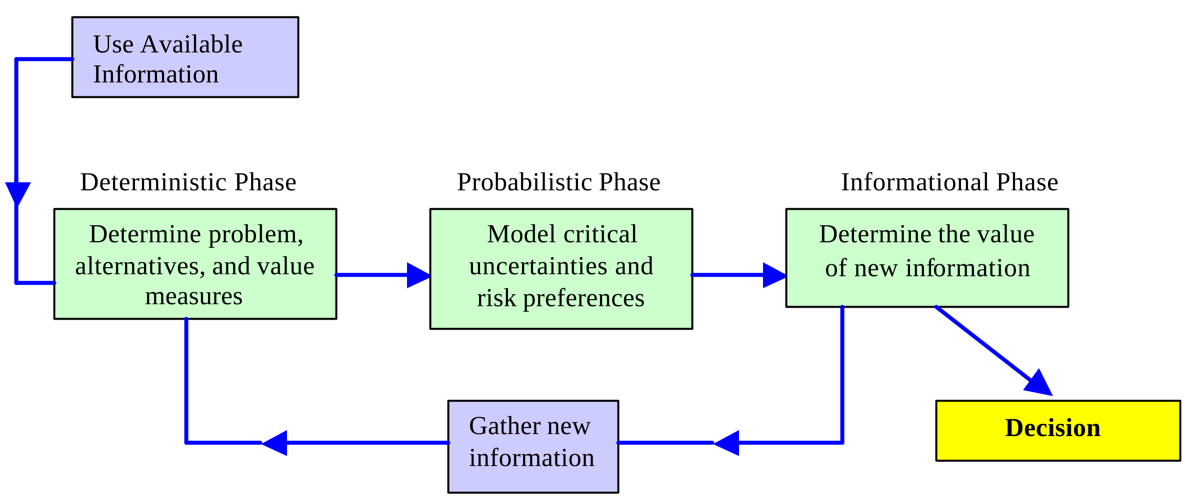
So what then constitutes a "good" decision? First, a good decision takes into account relevant information. Often, that requires sifting out which factors really matter and which are just annoying nuisances. Sometimes the factors we think will have the greatest impact on our decisions turn out not to have much impact whatsoever, while at other times, we may overlook something that does matter, but which we thought unimportant. Second, a good decision considers reasonable alternatives. It is easy to make a decision when there is only one option; conversely, choosing among thousands of alternatives can be exceedingly problematic. Thus, some initial winnowing of alternatives is often required so that sufficient resources can be devoted to evaluating the alternatives that remain. Third, a good decision can reveal when we need more information. Sometimes, but not always, it's worth paying for new information that clarifies the nature of the uncertainties faced. Fourth, a good decision is not only judged by its outcome, because even good decisions can have adverse consequences. Forgoing an extended warranty on that new computer may have been a good decision based on reported reliability and the price of the warranty, but that is little comfort for the owner whose computer expires one day after its warranty ends. Contrarily, purchasing an extended warranty and never having to use it could also be perceived as a "bad" decision.

One approach for sound decision-making is known as Decision Analysis. This is a structured "process," logical, step-by-step approach to working through complex, and perhaps initially unstructured or even unclear problems. A schematic of the decision analysis process is shown in Figure 8.1. More detailed discussion of the process is presented in Appendix B.

The process can be separated into three distinct phases: deterministic, probabilistic, and informational. The deterministic phase begins by structuring the problem to be solved. That is done by first defining goals and identifying a set of alternative decisions that can be made. The next step in the deterministic phase is to develop an empirical model that can value the agreed to specific goals. This allows decision makers to measure how successfully each decision alternative achieves the identified goals. The deterministic phase can be used to weed out variables that, even though subject to future uncertainty, will have little effect on the results.

The probabilistic phase takes the remaining variables and determines their effects on the overall values of the decision alternatives. The key step in the probabilistic phase is to represent the uncertainties of the important decision variables. For example, future electric market prices will affect the value associated with building a new generating plant today. In the probabilistic phase, that price uncertainty would be described analytically. In this phase, an analyst would also determine whether there were correlations among the different variables, such as between electric and natural gas prices. It continues by calculating relevant probability distributions of values for each alternative, and then constructing and solving a decision "tree" to identify the preferred strategy.

Figure 8.1 The Decision Analysis Process



The informational phase estimates the value of gathering additional information to reduce the identified uncertainties. The value of information can then be compared to the cost of obtaining new information that may be available before having to make a decision. In essence the value of eliminating different uncertainties is determined.

DA can be compared with analytic techniques like scenario analysis and Monte-Carlo modeling. The technique appears to offer a promising approach to addressing some of the complex sets of choices that utilities are sometimes presented in the face of substantial uncertainty, and in the face of decisions with their own contingent outcomes and uncertainties. We recommend that utilities explore and identify tools, such as the decision analysis tool, that can provide a sound framework for identifying least cost solutions in the face of complex and uncertain need determinations. The framework appears particularly useful in developing and implementing least-cost resource strategies in the new world of distributed utility planning.

DISTRIBUTED UTILITY (DU) PLANNING AND DISTRIBUTED GENERATION

Distributed Utility planning is a concept that has developed gradually since the late 1980s. In essence, it is a planning approach that evaluates augmentation or replacement of traditional central station generation and the transmission and distribution infrastructure necessary to deliver electricity generated to final customers with local generation and demand side management resources. The central-station generation concept developed over time for electric utilities because of increasing economies of scale in generation and technological improvements in long-distance, high-voltage transmission capabilities. As generation costs and line losses decreased, it made good economic sense to site generation facilities far away from population centers, and thus reduce the local environmental impacts of generation facilities.

In the 1980s scale economies began to be exhausted. Generating facilities capable of providing several thousand MegaWatts (MW) were being constructed, and further scale increases did not promise additional cost reductions. Siting of large-scale facilities also became increasingly difficult, even in the remote locations favored by developers and utilities. Moreover, smaller-scale generating units, such as micro-turbines, small engines, and fuel cells, have also decreased in cost. Although still more expensive than large-scale central station generating units, these new generating resource technologies have continued to decrease in cost, thanks to continuing technical innovations and the gradual emergence of their own scale economies. Distributed Generation (DG) is characterized as small (at least in relation to traditional central station generators), independently owned, and interconnected to lower voltage lines.

As new, modular technologies have decreased in cost relative to their large-scale counterparts, the emergence of a new utility design, encompassing generating units and targeted demand-side management resources throughout utility service territories has emerged as a viable economic concept. (Chapter 5 provided a summary of existing and emerging technologies relevant to DU planning.) Coupled with electric industry restructuring and the creation of separate local DU, and new transmission pricing concepts such as Locational Marginal Pricing (LMP), DU planning is a concept whose time has come in Vermont.

DU planning and distributed resources are not a panacea for Vermont. Siting small-scale generating facilities can be controversial, owing both to local resistance to site generating resources near population centers, as well as specific air pollution regulations that limit local operation of generating resources in order to maintain Vermont's "attainment" status under the Clean Air Act.

There are additional regulatory issues as well, including financing and ownership of distributed resources, and ensuring that distributed resources provide the generation and local transmission/distribution capacity advertised. Finally, there are issues surrounding evaluation of "economic" distributed resources determining when the benefits of flexibility and modularity exceed the benefits of scale economies. Distributed generation resources, may nonetheless, provide the preferred or least-cost solution. Utilities will need to work with customers to ensure that such barriers can be overcome in order to meet the requirements for least-cost delivery of services.

In the next section, the regulatory history of DU planning in Vermont, which began in earnest in the mid-1990s, is discussed. Next, we discuss the economic underpinnings of evaluating distributed resources to determine appropriate “least-cost” alternatives. This is followed by a discussion of future challenges for DU planning efforts in Vermont. Also presented below is review of the Area Specific Collaboratives (ASC) that emerged from Docket No. 6290.

A BRIEF REGULATORY HISTORY OF DU PLANNING IN VERMONT

The first attempt at a fully integrated DU planning exercise in Vermont was undertaken in 1995 by Green Mountain Power (GMP). This exercise considered the alternatives to traditional “poles and wires” investments to serve a proposed expansion at Sugarbush. The goal of the exercise was to determine the least-cost combination of demand-side management, distributed generation, and T&D solutions that would meet Sugarbush’s proposed capacity needs. In Docket No. 5983, the PSB discussed GMP’s DU Planning efforts, stating that:

> GMP has initiated a new approach to utility resource planning, referred to as distributed utility planning. It is designed to better integrate T&D investments and related activities into the utility’s overall planning effort. It appears to us that GMP has made a reasonable first attempt at DU-IRP. We recognize, as does the DPS, that the topic of DU-IRP is, in many respects, a new discipline. The DPS also agrees that GMP’s efforts have provided an opportunity to learn more about local-area T&D planning, the targeting of DSM efforts, and issues related to the integration of DU-IRP into other utility disciplines.[4]

DU planning efforts in Vermont gained impetus with the PSB’s Order in Docket No. 5980. Specifically, in the approved Memorandum of Understanding accompanying the PSB’s Order, the utilities, DPS and other signatories called on the PSB to:

> Initiate a collaborative process to establish guidelines for distributed utility planning by Vermont DUs. One objective of DUP is to explore options for using DSM and distributed generation to reduce the cost of maintaining the reliability of power delivery, by avoiding or deferring transmission, distribution, and other network investments. The MOU provides that electric utilities must engage in least-cost transmission and distribution system planning and effectively implement such plans. Utility transmission and distribution planning activities will be conducted under DUP. The guidelines described in the Plan are to serve as a starting point for a collaborative process to develop rules and methods for DUP in Vermont. The collaborative will seek to provide to the PSB recommendations on, among other things, guidelines for use in DUP activities by individual electric utilities, procedures for revising IRP filings to reflect the principles and practices of DUP, and externalities and risk adjustments (including methodologies) to be used in DUP. Electric utilities are expected to develop the necessary skills and capabilities to perform DUP, and coordinate their activities with the EEU.[5]

The Plan referred to in the quoted text was the *Power to Save: A Plan to Transform Vermont’s*

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[4] Docket No. 5983, Order, February 27, 1998, at 155.
[5] Docket No. 5980, Order, September 30, 1999, at 57.

Energy Efficiency Markets (May 23, 1997), which had been produced by the DPS and which contained proposed DUP guidelines.

The collaborative resulting from Docket 5980 led to the development of an initial set of planning guidelines in September 2000. In Phase I of the initial stipulation between the DPS and the utilities, the parties agreed to use an initial set of Planning Guidelines for Distributed Utility Planning (DUP) analysis. Although there were disagreements among the parties in Phase I of the Collaborative, they agreed to attempt to resolve those differences in Phase II, and established a workplan to review the relevant issues. The Phase II collaborative resulted in a Memorandum of Understanding (MOU) approved by the PSB in January 2003. That later MOU attached avoided cost assumptions to be used in DU planning and created the ASC's.

Since the Guidelines and assumptions are based on data that originally appeared some six years ago, the DPS believes that it may be useful to revisit them and the assumptions used for DU Planning to better reflect current market conditions and changes in the region's transmission pricing rules.

DISTRIBUTED GENERATION (DG) AND INTERCONNECTION STANDARDS

Distributed Generation in Vermont and other states typically rely on renewable fuels. They include inverter-based, induction, and synchronous generators, listed in order of complexity with regard to interconnection.[6] Examples of DG in Vermont include wind generators, microturbines, photovoltaic (PV), methane-fueled generators, and other types of customer-owned, behind-the-fence generators. Inverter-based DG's generally are preferable from an interconnection standpoint, as they do not produce fault currents and transients often encountered on induction or synchronous machines.

For several decades, federal laws under PURPA designated generators rated less than 80 MW and with overall efficiency of greater than 50 % as Qualifying Facilities. Electric utilities were obligated to pay generators achieving QF status payments based on avoided costs. More recently, the Federal Energy Regulatory Commission (FERC) has adopted interconnection standards for large (greater than 20 MW) and small generators (20 MW and less) as a mandatory component of Open Access Transmission Tariffs (OATT) for jurisdictional utilities. The rules for large generators are final, while small generator rules have been developed but are under review. Each set forth application requirements such as review methods, screening criteria, unit performance standards, interconnection studies, and cost responsibility but excludes payments for generation output.

FERC's interconnection standards apply only to requests for interconnection on jurisdictional transmission facilities or to distribution facilities where exports are anticipated. All other interconnection requests would be subject to state interconnection standards. Notably, only a few states such as New York, Texas, and California have fully developed interconnections standards, although several other states such as Massachusetts have made substantial progress. FERC rules for small generators likely will be employed as a proxy in states which do not have or that do not plan to develop interconnection standards.

[6] As a rule of thumb, purchasers of rotating devices less than 1MW usually select induction rather than synchronous machines due to cost.

Vermont interconnection standards and requirements for net metered installations are set forth in Rule 5.100. Most interconnections involving small, independently owned generators have been achieved via negotiation with the local utilities.

Vermont has addressed DG in the context of DUP and IRP. In the approved Phase II MOU in Docket 6290, the parties agreed that, for DUP DG, the interconnection standards that shall apply are the Institute of Electrical and Electronic Engineers (IEEE) standards P1547, unless the utility and the DG operator agree otherwise.

A key issue Vermont needs to address for DG options is back up or standby rates, as the cost of standby service can be a major determinant in the cost-effectiveness of DG. Utilities in some states (New York and Massachusetts) have tariff-based rates for back-up service while other states are addressing back-up rates. The imposition of back-up rates for DG interconnections often is highly contentious.[7]

The economic value of Distributed Generation may be further affected by adoption of nodal pricing currently before FERC.[8] Although many Distributed Generation units will interconnect to distribution systems, the presence of them on a higher-cost node may benefit loads connected to the node as the amount the loads pay will decline to a greater degree than nodes where costs are lower. Existing DG rules in other states and Vermont do not recognize this potential benefit. Local DG may also serve to defer transmission investments, both high voltage and subtransmission, if the penetration and diversity of DG in an area is sufficiently high. Establishing a clear and consistent credit mechanism is a significant challenge due to regulatory and institutional issues. For example, some high load factor DG technologies may be considered more "firm" from a capacity standpoint than lower capacity factor DG such as wind and PV technologies. It is likely that DG with lower capacity factors will provide mostly energy benefits. Such technologies would still provide benefits to loads located on higher cost nodes and such value should be reflected in area planning. The DPS is currently addressing DUP options for ten constrained areas in Vermont through established Area Specific Collaboratives discussed below. The ISO-NE RTEP03 report includes DG, but does not expect significant penetration for at least 10 to 15 years.[9]

AREA SPECIFIC COLLABORATIVES AND DISTRIBUTED UTILITY PLANNING

As part of the Phase II Memorandum of Understanding in Docket No. 6290, ten different Area

[7] Developing back-up rates applicable to all interconnections requested is particularly challenging given the DG technology type and application. For example, DG uses include emergency power, peak shaving, combined heat and power, base load and low capacity factor applications. Each may have distinct capacity factors, load following features, protection requirements, maintenance schedules and other operating conditions that can create a wide range of standby charges, some of which may preclude the cost-effectiveness of the technology.

[8] Even under current zonal pricing, the value of DG can be high and reflect the value of the distribution system constraint, however, under such circumstances, the cost of the constraint is effectively "socialized" across all nodes in the zone. The full value of the DG may not be fully recognized by the load serving entity in the local area of the constraint.

[9] The reason for the lag is not readily apparent. However, the current glut of generation capacity in the region may be influencing the siting of any generation source, whether utility-scale, or small-scale DG.

Specific Collaboratives were formed. (Appendix E shows the affected areas in relation to patterns of population growth.) The ASC's include areas where local distribution and/or subtransmission, and possibly high voltage transmission systems are or soon will be unable to reliably serve area load.

The list of ASC's include the following areas:

- Central Area DUP Target Area
- Milton Distribution DUP Target Area
- Milton Subtransmission DUP Target Area
- Southern Loop DUP Target Area
- Stratton Distribution DUP Target Area
- Tafts Corner Substation DUP Target Area
- Digital Injection Line DUP Target Area
- Lamoille County Loop DUP Target Area
- Mount Snow DUP Target Area
- White River Junction DUP Target Area

An eleventh ASC addressing the Burlington waterfront was formed in late 2003. Each has focused on a specific local area in Vermont where local area T&D capacity resources are either constrained today or forecast to be constrained as a result of anticipated growth in the near future.[10]

The first ASC to be completed was the Digital Injection site (Docket No. 6797), on March 27, 2003. Two others, a combined one examining the Milton sub-transmission and Milton distribution, and one for the Central Area and Killington Ski Area, have been put on hold, as anticipated local load growth has declined. The parties agreed to continue to monitor load growth in these areas, and reconvene the ASC when the parties felt the time was right for evaluating alternatives. More recently, the White River Junction ASC was completed in April 2004.

The remaining ASCs continue. Under the rules agreed to by the participating parties in Docket No. 6290, the ASC negotiations are treated as confidential until the parties file decisions with the PSB. Under a stipulation, quarterly status reports are filed with the PSB for each ASC until its completion.[11]

The MOU in Docket No. 6290 attaches a form for the selection of local areas for DUP analysis. A decision using this form has the legal status of a presumption that can be challenged before the PSB. The form provides the utility with a "checklist" to determine the likelihood that DSM and DG alternatives could meet local area capacity needs and succeed in deferring the need for T&D investments.

[10] The Burlington waterfront ASC was formed as a result of a desire by the City of Burlington to remove several existing overhead transmission and distribution lines along its waterfront, rather than a specific local area constraint.

[11] Copies of the quarterly status reports can be obtained from the PSB or the DPS.

DUP: CHALLENGES FOR THE FUTURE

As DUP has evolved in Vermont, several challenges have emerged. First, there is tension between the desire to use fossil-fuel based distributed generation resources, such as natural gas-fired combustion turbines or small diesel engines to meet local area capacity constraints and the need to avoid increases in local area air pollution levels. According to the Agency of Natural Resources (ANR), Vermont meets "attainment" standards established under the U.S. Clean Air Act. If local pollution levels increase, Vermont could fall out of attainment, which would have adverse financial consequences on the state. The DPS believes that Vermont's electric utilities, the PSB, and the ANR should work collaboratively to determine model siting-guidelines for fossil-fueled distributed generation resources (and biomass resources) to ensure that utilities are not caught between different regulatory standards and priorities. Development of such guidelines will help reduce the costs borne by ratepayers while at the same time ensuring that Vermont's air quality is not jeopardized.[12]

A second issue associated with siting all types of distributed generation is the need to minimize adverse local environmental impacts, including aesthetic impacts. Siting most types of local generating units are likely to face local opposition by residents concerned about pollution, noise, and visual impacts, unless the distributed generation under consideration is located at relatively isolated industrial sites. Proposed distributed wind generation projects, for example, have been highly controversial because of their potential aesthetic impacts on ridgelines. Such projects will require an adequate transmission infrastructure with which to inject the electricity generated into the New England grid.

A third issue concerns the need to better integrate the transmission planning efforts of VELCO with its individual member utilities' local distribution planning efforts. Currently, VELCO has little involvement in local area planning activities, such as the ASCs. Yet, investments made at the local distribution level may affect VELCO's need for new transmission upgrades. Furthermore, there must be adequate interconnection standards to ensure that DG units are operated in a manner that does not destabilize the state's transmission system. The gap between VELCOs own planning and the delivery of generation or efficiency solutions requires a systematic and sustainable solution. The DPS will continue to work with the utilities to develop a framework that ensures that least cost solutions, be they generation, transmission, distribution, or efficiency can be secured. As outlined elsewhere in the Plan, ample opportunity must be given for meeting needs through appropriate T&D, distributed generation, efficiency services, and/or the delivery of such services through competitive market alternatives.

A fourth issue concerns specific regulatory and financial issues that can arise when distributed generation or DSM resources are selected as making up a least-cost set of local area capacity investments. Unlike "poles and wires" investments, both distributed generation and DSM resources provide energy benefits. In the case of distributed generation, there may be questions as to who will own generation units, how will the cost be financed, and how will the owners of such units be reimbursed? It will be important to develop clear guidelines for ownership and financing to ensure that there are no barriers to development of cost-effective DSM in specific local areas.

[12] This proposal parallels similar proposals for wind-siting following the work of the Advisory Commission on Commercial Wind Energy. Final recommendation were delivered to the Governor on December 15, 2004 and are available on the DPS web site www.state.vt.us/psd. See also, the discussion in Chapter 5 and the action Plan discussion in Chapter 11.

A fifth issue concerns operational guidelines and standby rates for customers who install distributed generation to both meet their own generation needs and to provide local area capacity support. Not only must these customers agree to dispatch their distributed resources as required by the local utility (assuming the resource is dispatchable, like a combustion turbine), but there must be adequate steps to ensure that unexpected unavailability of the customer's distributed generation does not exacerbate local area capacity constraints and impose costs on other utility ratepayers.

DU PLANNING: NEXT STEPS

One of the conclusions reached in the semi-annual DU Planning meetings (which are required under the terms of the Phase II MOU in Docket 6290) is the need to upgrade the avoided cost data that has been used in the ASCs to determine the availability of cost-effective DSM alternatives. In addition, it may be appropriate for DPS to work with utilities to review appropriate planning and analysis tools, including tools that begin to examine appropriate levels of reliability for specific areas, and whether there is a need to develop specific local area reliability standards. The DPS believes this latter issue will become more important given the increasing importance of electricity in Vermont's economy.

RECOMMENDATIONS

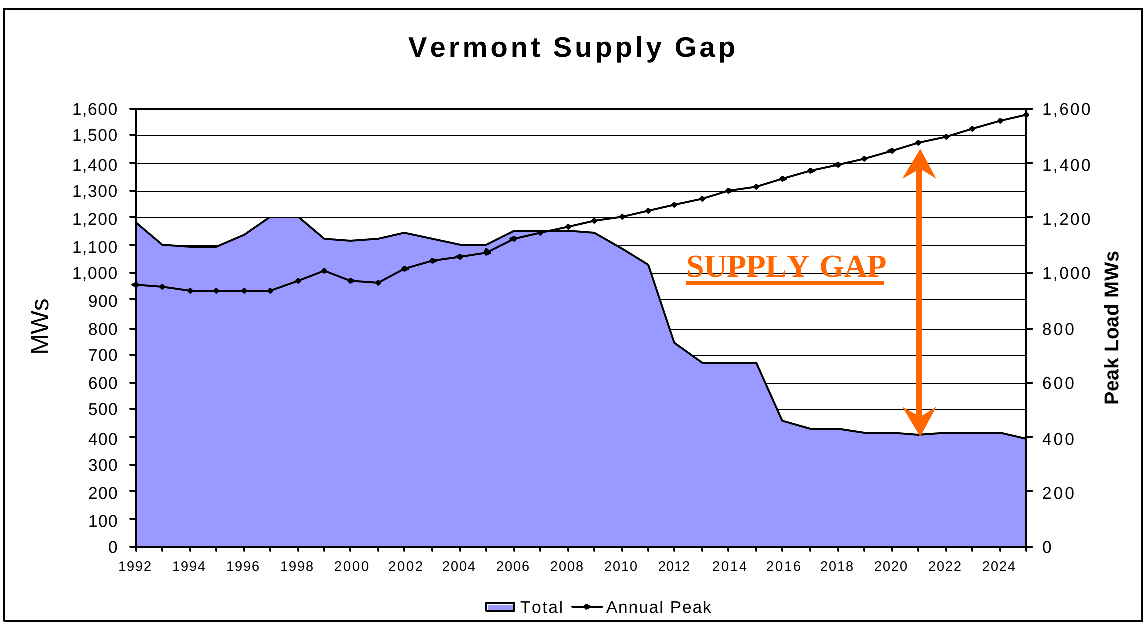
- Vermont regulators and utilities should review the IRP process and implementation to ensure sound management decision-making is occurring and that the current process is being used effectively.
- Vermont utilities should employ advanced decision and analytic techniques in electric utility integrated resource plans and DUP.
- As new integrated resource plans are developed and submitted, these plans should adequately account for uncertainties regarding future load growth, fossil fuel prices, wholesale electric prices, environmental cost considerations, and the costs of new, cleaner generation technologies.
- Vermont stakeholders, including electric utilities, utility regulators, those with expertise in developing and deploying DG systems, and ANR should work collaboratively to determine model siting guidelines for fossil-fueled distributed generation resources (and biomass resources). Vermont regulators and utilities should establish appropriate backup rates for DG resources.

Chapter 9: Designing Resource Portfolios for 2015, 2025 and Beyond

INTRODUCTION

The challenge for Vermont's future is to meet its electric energy needs in a way that is adequate, reliable, secure, affordable, efficient, and environmentally sound.[1] The path to achieving these objectives is not paved with simple solutions. There is no electric resource that offers a "perfect" solution. All of Vermont's electric resource choices require tradeoffs among cost, adequacy, reliability, efficiency, and environmental impact. The magnitude of the challenge is further increased by the fact we do not know, with any certainty, what the rules, structure or status of the market will be in the next three years, let alone in 2015 or 2025.

Figure 9-1



Today, Vermont's electric portfolio is heavily concentrated in just two resources: Hydro Québec (HQ) and Vermont Yankee (VY), which supply two-thirds (about 600 MegaWatts (MW)) of the state's peak electricity demand. As Figure 9-1 shows, Vermont has enough resources to meet the bulk of its needs through 2012. When the VY contract expires in 2012, a significant amount (about 300 MW) of Vermont's resource supply will need to be replaced. Further exacerbating Vermont's coming supply gap is the ramping down of the committed supply under the Hydro Québec/Vermont Joint Owners (HQ/VJO) contract from a high of 305 MW through 2012 down to 31 MW in 2016, with further declines thereafter. (See Table 9-1.) Furthermore, there is at least some risk of loss of power from VY as early as 2007 due to exhaustion of on-site, high-level nuclear waste storage, unless additional

[1] Title 30 V.S.A §202a

storage is approved. (For more detail, see the discussion of VY in Chapter 4.)

Table 9-1

HQ - HQ/VJO RAMP-DOWN 2012-2015	
YEAR	**MW**
Through 2012	305
2013	249
2014	249
2015	249
2016	31
2017	6
2018	6

One should note that the way of doing business in the electric industry has change since the initial HQ and VY contracts were implemented. The establishment of an active New England wholesale market administered by an Independent System Operator (ISO-NE) and the creation of a merchant generation supply has moved the resource procurement paradigm from long term buying and build-your-own generation to the paradigm of a commodity based market.[2] The electric power market has become like any other traded commodity market with all the physical and financial instruments available for inclusion in a resource portfolio. (For more detail, see the discussion in Chapter 7.) It is imperative that those responsible for resource procurement and management understand the options available in constructing and managing a portfolio. In the context of these emerging markets, traditional investments in owned generation or long-term contract commitments can serve as a hedge from exposure to the prevailing market conditions.

The time is now for Vermont to begin planning how and when to increase the diversity of its electric resource portfolio. This will mean including more resource types and suppliers and different types of pricing contracts to reduce the risk of market uncertainty and supply disruptions. Ultimately, the goal must be for Vermont to have a diverse electric supply portfolio both in terms of the duration and type of power supply.

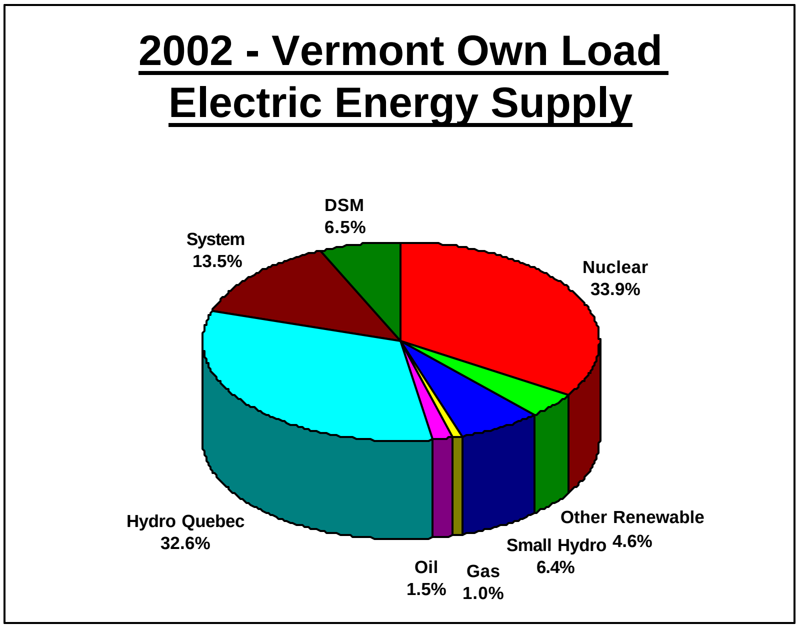
CURRENT ELECTRIC PORTFOLIO

The composition, benefits, environmental impact, and shortcomings of Vermont's current resource portfolio are discussed in Chapter 4. A brief reiteration of the portfolio composition is: 34% Nuclear, 32% HQ, 13.5% System (Market), 6.5% DSM, 6.4% Small Hydro (Instate), 4.6% Other Renewables, 1.5% Oil and 1% Gas. Some existing resources will likely have to be replaced (especially VY and HQ) and additional resources will be needed to meet increased growth in load. The challenge is to

[2] At present, the commodity that is traded is typically short-term in nature (day-ahead or real-time). Increasingly long term purchases of the electricity commodity are being freely traded through merchantile exchanges such as NYMEX. Liquid markets are now available for "strips" of electricity over periods of days, weeks, or even several years over defined period. As the market develops and matures, it seems likely that new products and longer-term commodity purchases will evolve.

meet Vermont's electric energy needs in a way that addresses the goals of adequate, reliable, secure, affordable, efficient, and environmentally sound energy.

Figure 9-2



REPRESENTATIVE ELECTRIC PORTFOLIOS IN 2015 AND 2025

This plan, like the 1994 Plan, does not and cannot responsibly prescribe a specific electric supply portfolio for Vermont utilities. The electricity market is complex and ever changing. Utility managers are expected to develop a sound decision-making framework that assures sound planning and decision-making at the time that decisions can or must be made. Nevertheless, it provides a useful perspective to think about what Vermont's future supply portfolio might look like. As part of a Public Workshop process held in March 2004, participants were asked to develop what they considered to be a viable resource portfolio for 2015 and how that should evolve going forward to 2025. The primary purpose of the exercise was to layout a path toward goals that are desirable from a worldview today. The exercise was comprised of an examination of the current resource mix, an identification of future needs, an identification of possible actions in the event of extraordinary occurrences, and a discussion of the relative merits of resource options, proposed goals and approaches. The results of the exercise are presented in Figures 9-3 and 9-4. The portfolios represent a consensus among participants. The economic impact and relative merits of the portfolios were not evaluated, nor were specifics of the timeline to achieving the goals. The portfolios were developed from a statewide perspective and may or may not meet the least cost criteria for a specific utility. In order to comply with this *Twenty Year Electric Plan* and to obtain a determination of compliance with 30 V.S.A. "202(f), 248(b)(6), and other statutes, Vermont utilities must follow the provisions of Docket 5270 and other Public Service Board (PSB) Orders and Appendix A of this Plan.

Figure 9-3

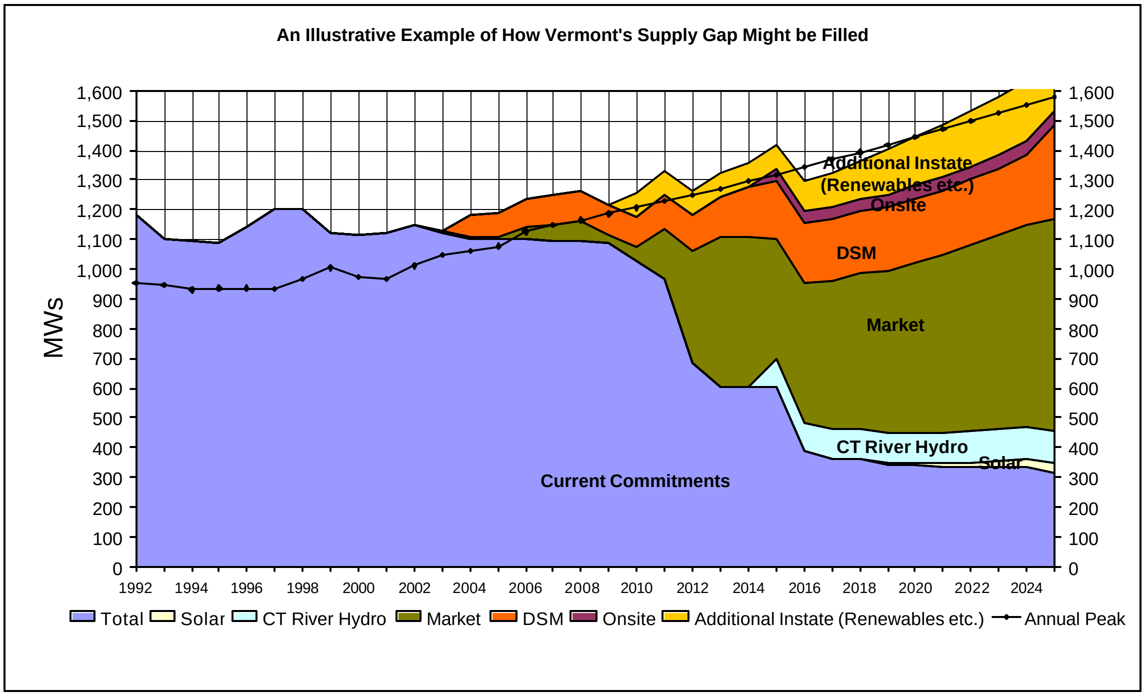
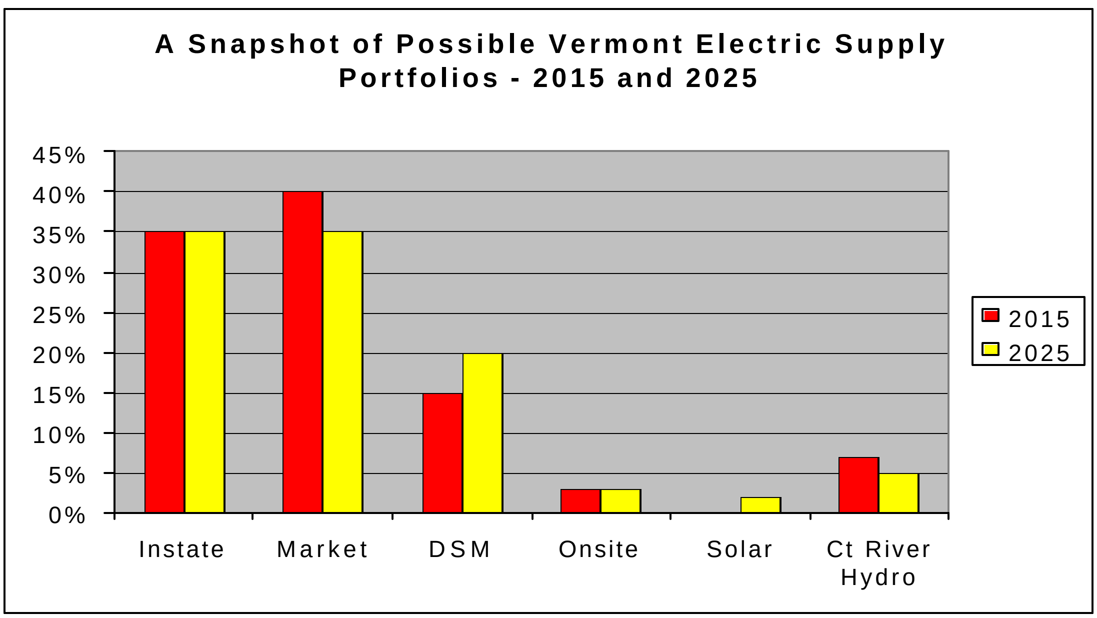
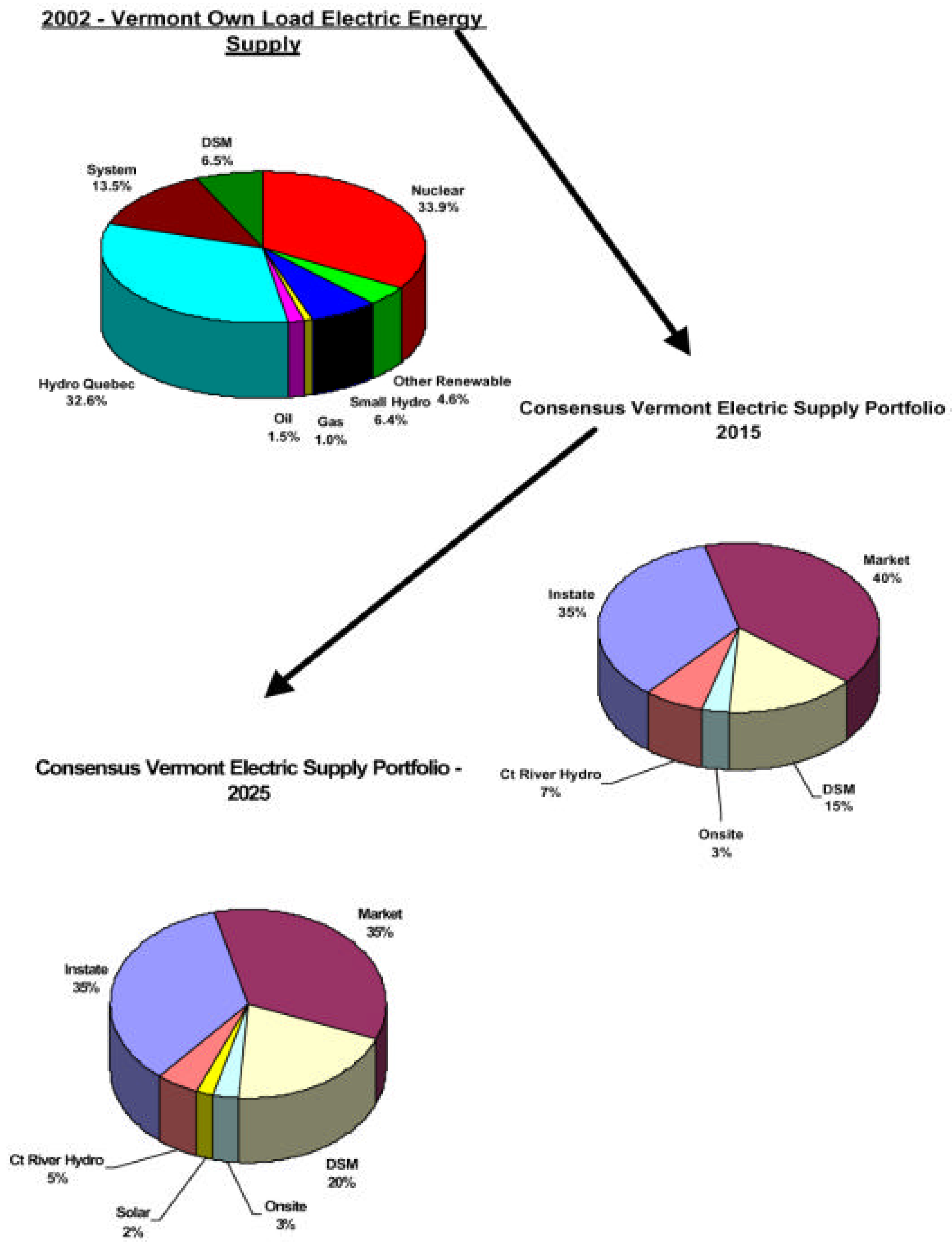


Figure 9-4



In Figure 9-3 the categories are presented as Market, In-state, On-site, Connecticut Hydro, and Demand Side Management (DSM). Market refers to any combination of instruments, be it contracts (perhaps an extension of the relationship with HQ), options or spot market purchases. In-state generation includes, but is not limited to wind, biomass and, in the event of license renewal of VY, some nuclear energy. On-site refers to distributed generation and, as with in-state, is not limited by appropriateness of type of generation regarding environmental and aesthetic impact.

Figure 9-5 Workshop Consensus Portfolio Evolution 2002-2025



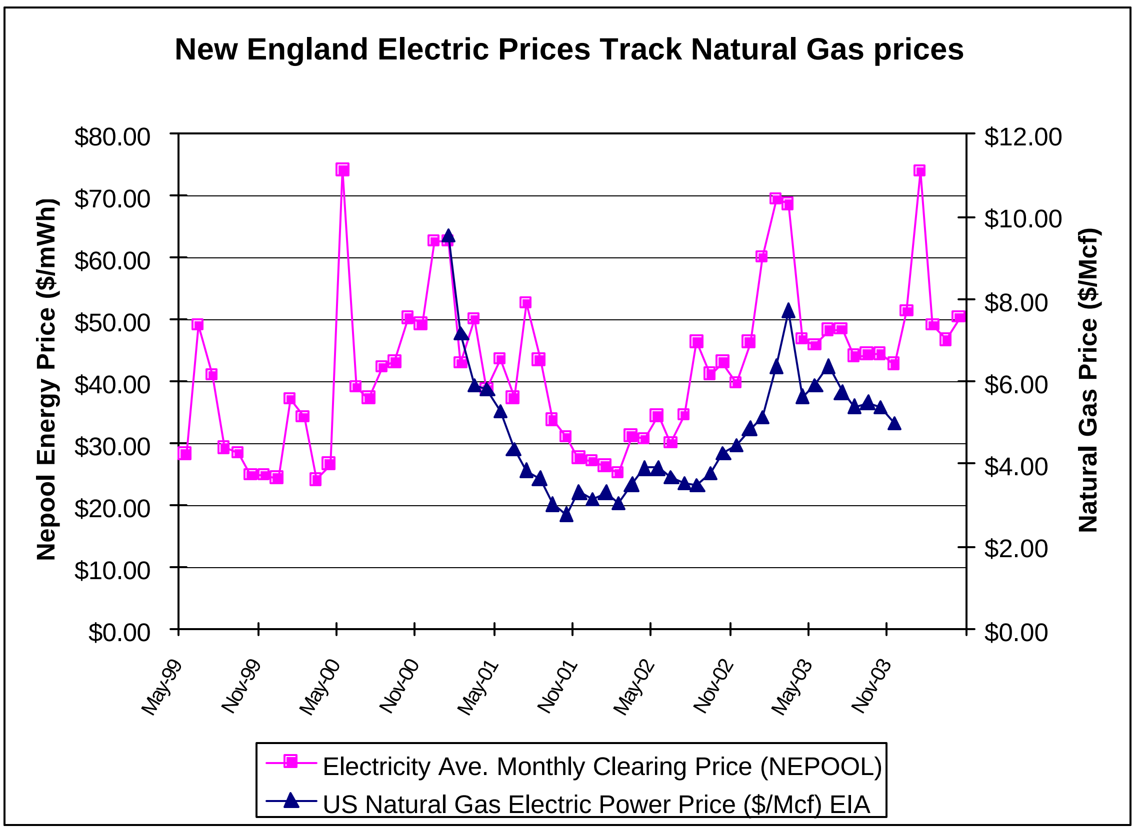
Benefits of the proffered portfolios are a degree of local control while still being able to access positive moves in the market; a degree of insulation from market volatility; and the reduction in load requirement via DSM. Figure 9-5 is illustrative of how the 2015 & 2025 targets could be approached.

FACTORS INFLUENCING THE MARKET PRICE OF ELECTRICITY

Like any other commodity, the market price of electricity is subject to the law of supply and demand. The supply/demand function for electricity differs from a typical commodity in that, unlike coffee, corn or oil, which can be logistically and economically stored; electricity is consumed as it is produced. The exception is hydropower, which has storage capability in reservoirs. The demand for electricity is 24/7 and varies with peaks in demand over a 24-hour period that can range 100% greater than the daily minimum. The consequence of lack of storage is that installed generating capacity must be greater than peak demand (a reserve of 10% is generally required for backup in the event of failure of some of the network units).

The price for wholesale electric energy depends on three primary drivers: fuel cost, load, and available generating capacity. The following sections analyze the effect of each of these components.

Figure 9-6



FUEL COSTS

In the past decade nearly all of new generating facilities to come online in New England were non-fuel-switchable natural gas plants. The primary reason for development of this fuel monoculture has been because of the environmental attributes of natural gas plants. The consequence of this transition to a regional fuel-monoculture has been a coupling of the wholesale eclectic price to the price of natural gas. Figure 9-6 is illustrative of how closely the wholesale electric market price tracks the price of natural gas. The Northeast is heavily dependent on natural gas for space heating in the winter and as an industrial source of energy year round. The growth in using gas for electric generation has put additional pressure on the constrained regional gas supply.

The current constraint in the gas supply is driving the price of electricity and is expected to continue doing so until new supply and transmission resources are brought online to service the Northeast. Natural gas is expected to be the primary price driver for the next few years (approximately through 2007 or 2008). The magnitude of the impact will be dependent on meteorological factors and the strength of an economic recovery.

DEMAND

Figure 9-7 presents the data from an extraordinary day and is illustrative of a day of extreme price swings due to constrained supply caused by heavy load and unavailability of units. In contrast, Figure 9-8 represents a typical 48-hour trading period. In Figure 9-8, load and meteorological conditions are moderate. The price is represented by a sixth order polynomial trend line and the actual prices are the blue rectangles. This figure data is a good example of the diurnal variations in load and the correlation with dependency of price on demand.

Figure 9-7

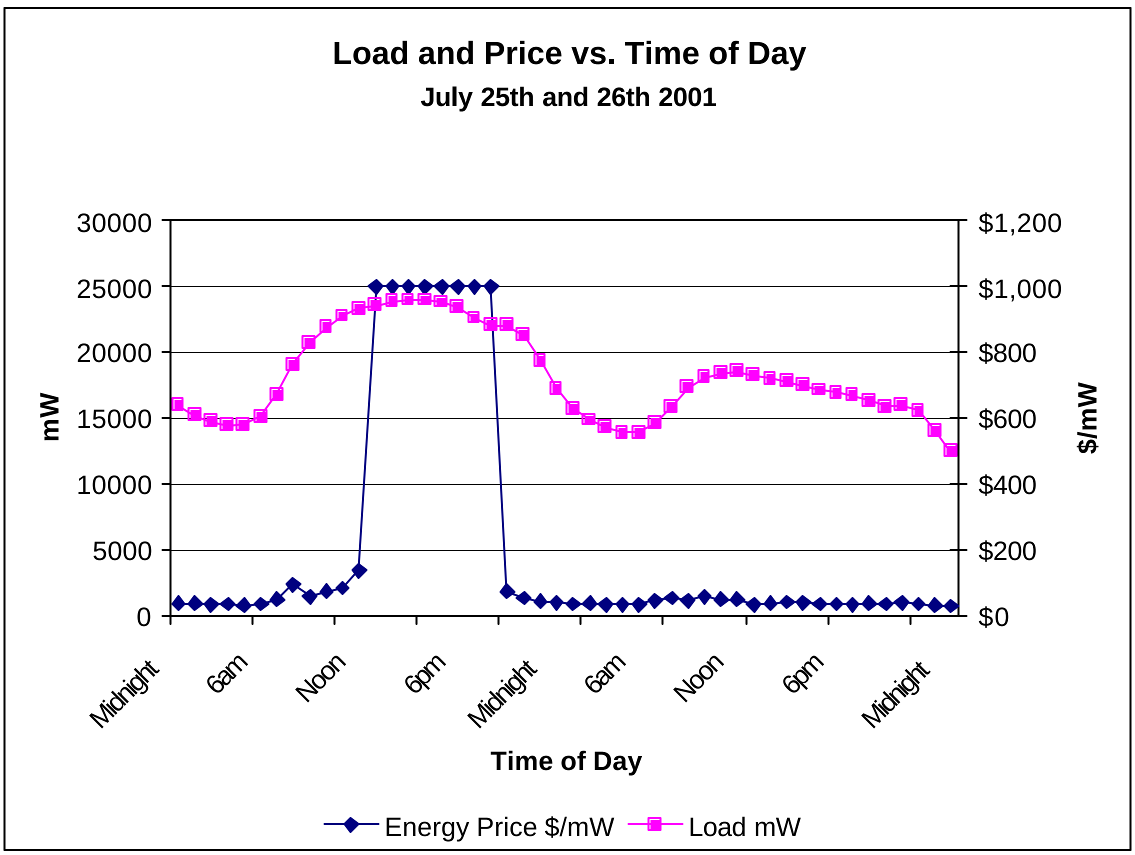
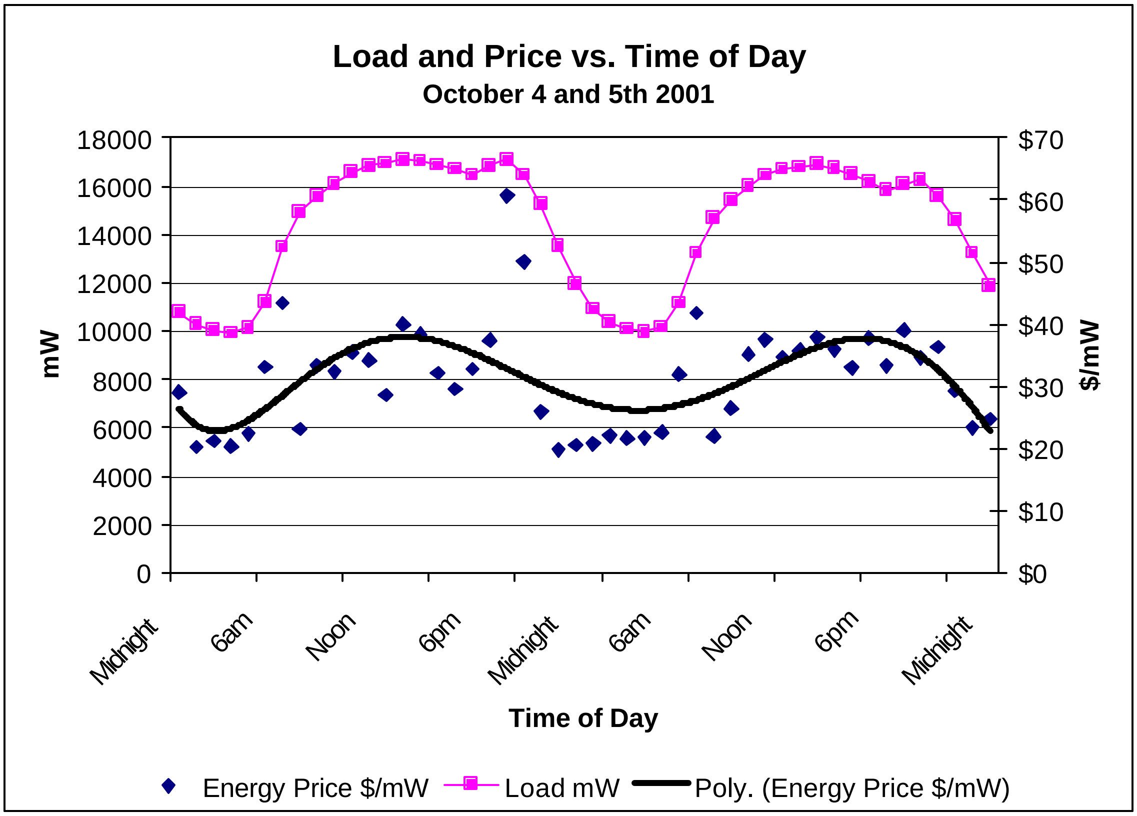


Figure 9-8



INSTALLED GENERATING CAPACITY

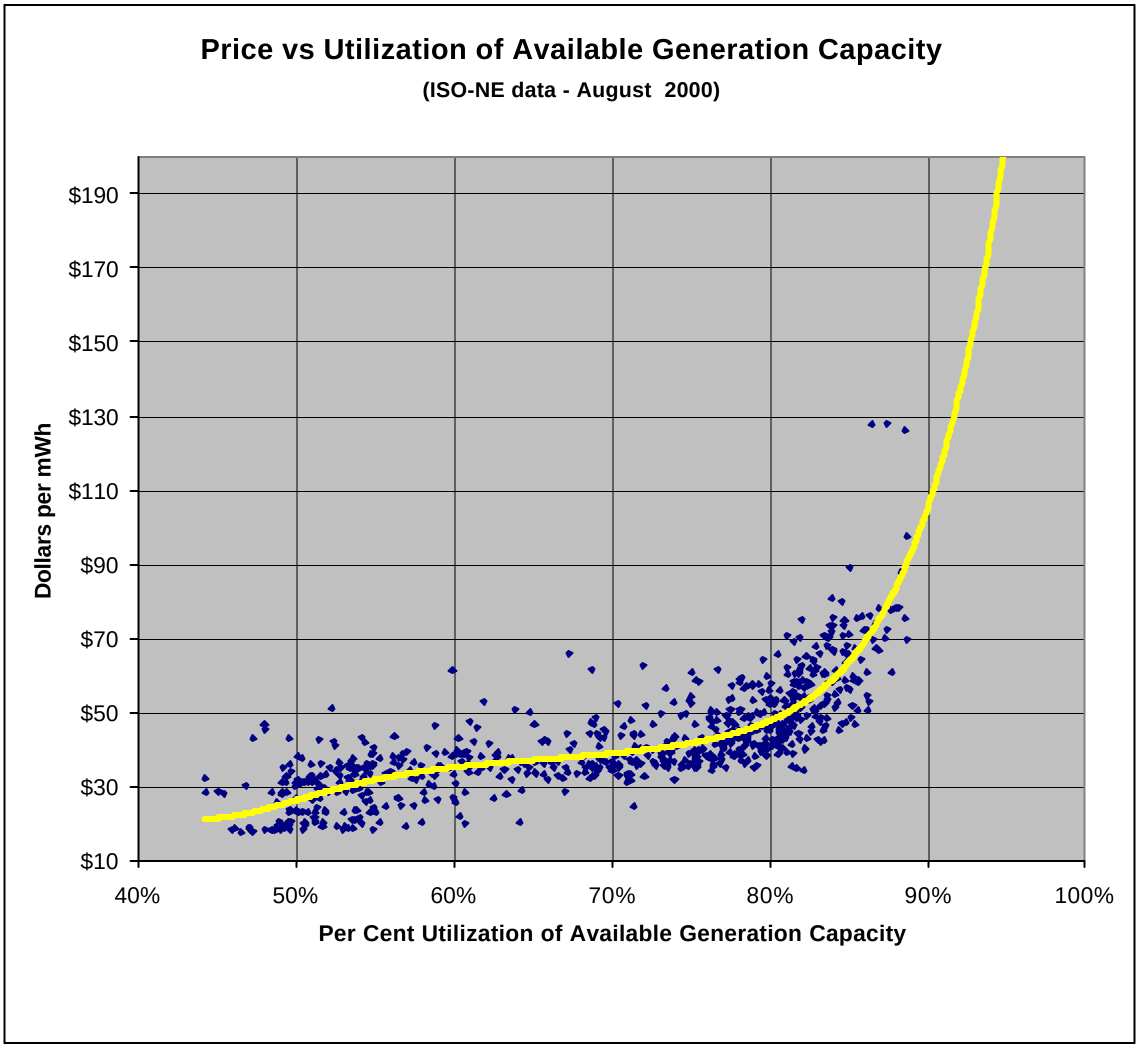
In determining the effect of capacity on price, it is important to utilize available capacity rather than total installed capacity. As discussed previously in this section, the inability to store electricity means that the generation must be instantaneously available to meet demand. Marketers in California quickly learned how the relationship between demand and available capacity could be manipulated to extract higher market prices. Evidence has come to light that shows how marketers created logjams on the transmission lines and shut down generation plants in order to raise prices.[3] Figure 9-9 demonstrates the dramatic exponential increase when the demand exceeds the 85% of available generation capacity.

As discussed earlier in this section, the current marginal energy price determinant for the New England region is the price of natural gas, which is expected to be the primary price driver for the next few years. As the price of natural gas begins to ease, it is likely that generating capacity constraints will begin to set the marginal energy price in New England. Figure 9-10 presents a case for this possibility. Currently, New England is in a period of surplus capacity due to the over building in the late 90's and early 2001. The building boom was driven by the restructuring, availability of funding and expectation by the merchant owners of profit realization. In New England, currently 33,000 MW of generation are installed. An approximate reserve requirement of 10% leaves 30,000 MW to serve load. ISO-NE is projecting this level of demand to be reached by 2010, driven by growth in the

[3] June 8: Energy Risk - Enron Tapes Inflame Californians, Ken Silverstein, Director, Energy Issues Analysis, Tuesday, June 8, 2004

summer peak. Around 2008, without any new merchant generation coming on line, supply will be reaching and exceeding the critical mass of 85% at which point prices will exhibit exponential increases.

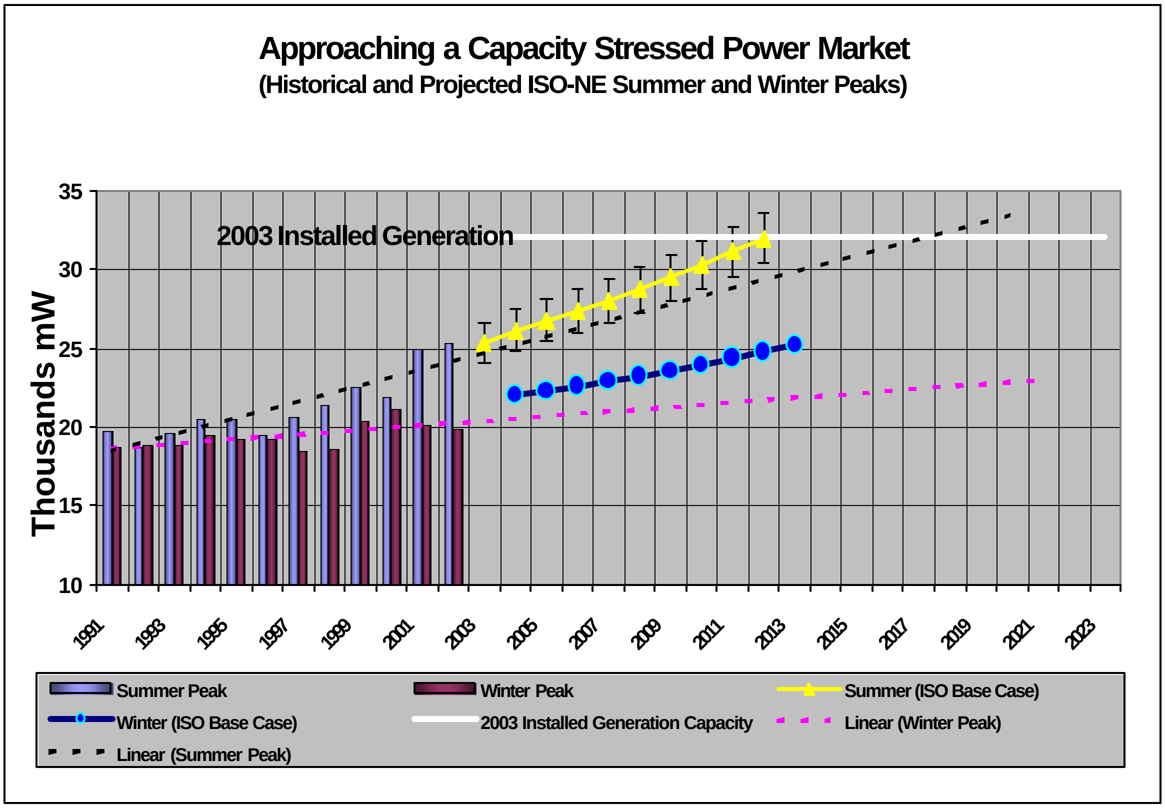
Figure 9-9



According to the U.S. Department of Energy's (DOE) Energy Information Administration (EIA) data no new merchant generation is currently planned in New England. This is primarily driven by the uncertainty that remains in the business model of merchant power and the reluctance of the capital markets to support these projects. Prior to the collapse of the merchant market, investors/lenders were willing to support projects based on expectations of projected cash flow. This has changed. Investors and lenders are now, and for the foreseeable future, requiring committed power purchase agreements before committing to financing a merchant project. These circumstances could present opportunities for buyers of power to negotiate well-structured power purchase agreements on favorable terms.

ISO-NE continues to advance its LICAP proposal as a means of providing stable payment to generators in return for their availability as reserve capacity. The Department of Public Service (DPS), the PSB, and peer counterparts in New England have been active participants in the proceeding to ensure that ratepayers do, in fact, receive the expected reliability in return for these payments.

Figure 9-10



In the interim, prior to the termination of the HQ and VY contracts, careful attention should be paid to developments and trends in the supply sector. Utilities should be aware and prepared to evaluate opportunities as they present themselves. A portion of the supply deficit due to the ramping down of the HQ between 2012 and 2015 and the expiration of the VY license in 2012 can and should be filled by new power purchase agreements. A few years ago, as the markets were embracing the concept of restructuring, there appeared to be less anticipated need for long term purchased power agreements. California, in its restructuring experiment, declared that power purchase agreements were void and had to be made through the market. The result was wildly fluctuating prices and supply instability, resulting in bankruptcy of some of the market players and nearly bankrupting the state. While bilateral supply contracts remain common, the duration of typical agreements is for shorter than historical experience.

It is paramount that the costly mistakes of the past not be repeated when structuring new power purchase agreements. All new contracts should be executed and performed in an atmosphere free from duress.

MAKING ELECTRIC PORTFOLIO CHOICES

Energy markets are fraught with uncertainty. It colors the way we must approach future energy resource decisions. No matter how much planning we do, the world is unlikely to cooperate. The unforeseen will arise and "unlikely" events will occur. That is the planner's lot.

Regulated utilities are expected to seek out and undertake actions that are beneficial to their ratepayers and fair to their owners. Management of a utility involves the careful balance of the interests of the investors and the ratepayers. The regulated utility has an obligation to deliver a low cost product to the ratepayer while returning a reasonable rate of return to the investors. Requisite to practical management is the utilization of decision analysis techniques in resource analysis, planning and decision making issues of uncertainty, risk, diversity, and flexibility. These techniques are the subject of Chapter 8. Table 9-2 illustrates strategies that utilities may employ to deal with risk under a variety of market conditions. The illustrative list of variables and table of strategies, while in no way comprehensive, is an example of the expansiveness of the decision analysis matrices that portfolio management entails.

A major component of electric rates is actual power costs that should be managed through ongoing exercises in decision analysis that review critical market and non-market uncertainties. All elements of a utility's power supply mix, both those in place and available as options, must be viewed as parts of an entire portfolio. Portfolio management will require utilities to balance costs and risk. This approach is well established in utility supply planning. The challenge of utility portfolio planning is to systematically apply this principle so as to spread known risks without overly increasing costs.

A starting point in developing a portfolio is to:

- Identify needs and horizon
- Identify the type of market cycle
  - Rising Price or Market Tops
  - Neutral – Prices Trend Within Narrow Range
  - Falling Prices or Market Bottoms
- Identify resources, including
  - Bilaterals
  - ISO Market
  - Owned Generation
  - Futures (ideally load following instruments)
  - Participation
- Determine acceptable levels of risk

Portfolios can be designed to meet power supply needs under a variety of scenarios. These can be characterized by probability distributions. A number of elements must be evaluated and balanced when composing portfolios under various scenarios, including:

- Price
- Diversity (fuel, duration, counter party, staggered mix, etc.)
- Flexibility
- Timing
- Long term vs. short term
- Use of financial hedging instruments (such as call/put options)
- Contracts vs. physical generation (“iron in ground”)
- Resources balanced between base, intermediate and peak supply characteristics
- Ultimate resource decision balance containment of cost with sufficient resource balance and risk tolerance

Table 9-2 Illustrative Risk Mitigation Matrix

Neutral – Prices trend within narrow range

Evaluate position and risk annually, more frequently in volatile markets
Use Neutral markets to establish strategic positions against either extreme rising of falling market conditions.

Unmet Need	Unmet Need Horizon			Exposure
	1- 2 yrs.	3-5 yrs.	5 – 10 yrs. and beyond	
Last 10% of load	ISO Market + Futures	ISO Market + Peaking Bilaterals	ISO Market + Peaking Capacity	
20 – 50% of load	ISO Market + Bilateral Contracts	Laddered Bilateral Contracts	Laddered Bilateral Contracts + Participation	More $ at stake
50 – 100% of load	Bilateral Contracts + Baseload Futures	Laddered Bilateral Contracts + Participation	Laddered Bilateral Contracts + Participation	Even more $ at stake

Rising Prices or Market Tops

- Minimize or avoid making commitment to long term contracts and participation – sellers will be demanding a premium and or buyer winds up paying above market when prices fall
- Avoid buying intermediate or long term at market tops. Ideally one would be positioned prior to run up as per Matrix I.
- Unanticipated needs should be covered for downside by short position.

*Try and be net seller

Unmet Need	Unmet Need Horizon			Exposure
	1- 2 yrs.	3-5 yrs.	5 – 10 yrs. and beyond	
Last 10% of load	ISO Market + Sell Futures Short	ISO Market + Sell Futures Short	Wait for market conditions to change	
20 – 50% of load	ISO Market + Short Term Bilateral Contracts	Short Term Laddered Bilateral Contracts	Wait for market conditions to change	More $ at stake
50 – 100% of load	Short Term Bilateral Contracts + Baseload Futures	Short Term Laddered Bilateral Contracts + Participation*	Wait for market conditions to change	Even more $ at stake

Falling Prices or Market Bottoms

- Lock up as much of anticipated need in long-term low rate contracts even if at slight premium over market.
- Sellers willing to sell long term
- Position for profiting from next up cycle in market

Unmet Need	Unmet Need Horizon			Exposure
	1- 2 yrs.	3-5 yrs.	5 – 10 yrs. and beyond	
Last 10% of load	ISO Market + Peaking Bilaterals	ISO Market + Peaking Bilaterals + Be Long Futures	ISO Market + Peaking Capacity + Peaking Bilaterals	
20 – 50% of load	ISO Market + Bilateral Contracts	Laddered Bilateral Contracts	Wait Laddered Bilateral Contracts longer term + Participation	More $ at stake

RECOMMENDATIONS

While it is not the objective of this chapter to define all the steps that will be needed in the future to obtain the electric portfolio that Vermont will need in 5, 10, or 20 years, there are a number of concrete steps that can be taken to begin to address Vermont's future energy needs. In addition to steps outlined in other chapters of the Plan, these are:

- Monitor and evaluate electric generating resource portfolio diversity. Ensure that Vermont's overall electric portfolio is sufficiently diverse, especially in light of the potential loss of major generating supplies.
- Look to mitigate the risk associated with reliance on a unit contingent contract with Vermont Yankee for such a significant portion of the annual energy needs of the State.
- Additionally, examine the implications of a potential license extension, since an application for extension will need to be submitted to the Nuclear Regulatory Commission within the next three years.
- If it becomes evident that VY is not to be shut down prematurely in 2007 or 2008 over a lack of new dry-cask storage, it will be important to begin planning for the plant's scheduled retirement or re-licensing in 2012.
- Continue to improve working relationships with HQ and begin more active negotiations with them for replacement power or its equivalent. Explore the potential for new hydroelectric or wind resource acquisitions when the existing HQ contract begins to expire in 2012.
- Ensure that there are specific plans for replacement of the HQ-VJO contract in place by January 2015.
- Given the uncertain outcome of Vermont's pursuit of an interest in the Connecticut River hydro facilities, the DPS and Vermont's utilities should begin discussions around possible in-state generation options, especially as a matter of reliability.

CHAPTER 10: Strategies to Control Electric Costs and Action Plan

INTRODUCTION

In 2003, the average price paid by residential and business customers in Vermont was over 11 cents per kiloWatt hour (kWh), compared with about 7.5 cents per kWh for the U.S. as a whole. Although Vermont's rural character necessarily contributes to higher overall electric rates, the cost of maintaining transmission and distribution facilities is spread over fewer customers, meaning higher costs and prices for all. The cost of generation accounts for about 60% of the average Vermont electric rate. The remaining 40% consists of about equal fractions of transmission, distribution, and administrative costs. Most distressingly, this disparity between the average rates Vermont's residential and business customers pay, and the average rates paid by customers in the U.S. as a whole, has steadily increased. In 1990, Vermont's residential electric rates were about 15% higher than the U.S. average, commercial rates were about twenty percent higher, and industrial rates were some 35% higher than the U.S. average. Today, that disparity has grown to about 50% for all three classes. Growth in the disparity is due in large part to the replacement of inexpensive older power contracts and sources with higher-priced long-term contracts and the related exposure to prevailing wholesale market conditions occurring during the decade of the '90s. Since 1990, Vermonters have paid over $2 billion in premiums over what they would have paid for electricity had Vermont's electric rates been comparable to the U.S. average. Currently the premium is approximately $200 million annually. On a regional basis, the cost differential is less dramatic, but still significant for commercial and residential customers.[1]

Over the past decade, Vermont's energy policy has favored actions designed to limit their total electric bill through aggressive Demand Side Management (DSM) programs. Those programs continue today under the auspices of Efficiency Vermont (EVT) and have been thoroughly discussed in previous chapters. Today, with this Plan, it is appropriate to consider another criterion: the impacts on electric rates. Both rates and bills are important to the state. The employers who provide the jobs that Vermont's citizens depend upon, are focused on how high rates have become—relative to what they are elsewhere—and how that has contributed to making Vermont less competitive. To keep those jobs, and add new ones Vermont must seek out ways to improve its cost competitiveness. At this time of heightened global competition and economic stress, Vermont's focus must be turned to improving its employers' relative cost competitiveness—while preserving its environmental and community values. This does not mean abandoning Vermont's energy efficiency efforts. Rather, it recognizes that energy efficiency alone is not sufficient to support the expansion of existing businesses and to

[1] According to DOE/EIA, rates for September 2004 were 3% above the New England average. Residential rates were 9% commercial rates were 5.5% and industrial rates were less than 1% above the New England average. . *See,* http://www.eia.doe.gov/cneaf/electricity/epm/table5_6_b.html

encourage the relocation and or development of new ones. To do that, Vermont must also address comparatively high marginal electric prices.

The relatively high prices of electricity in Vermont have had several adverse impacts, two of which should be noted. First, high energy prices have placed the state at a competitive disadvantage compared with other states. Commercial and industrial firms seeking to expand or relocate are less likely to choose Vermont than they are to choose other states having lower electric rates. These firms are the engines of a strong, vibrant, and diverse economy that provides good-paying jobs to citizens. Second, high rates have created an affordability problem for low-income residents that must be addressed.

Reducing the disparity in electric rates will not be easy, especially since Vermonters do not want low-cost, but environmentally poor generating resources in their backyards, and much of Vermont's energy requirements are served through long term contracts that will not expire until as late as 2012.

Since approximately 60% of the electric rate is tied to the cost of generation services, the greatest opportunity for realizing material rate reductions is by reducing the costs of existing generation resource commitments. As current resource contract commitments expire for Vermont Yankee (VY), Hydro-Quebec (HQ), and the contracts for independent power under PURPA, Vermont utilities will have an opportunity to do just that in the process of choosing future sources.

There are, however, a number of strategies that Vermont can consider to reduce rate disparity, improve competitiveness, and reduce affordability problems for low-income consumers. These strategies can be grouped into the following categories:

1. Effective resource selection and decision-making (See Chapter 8 for a full discussion of this category);
2. Energy portfolio diversification (See Chapter 9 for a full discussion of this category).
3. Alternative performance-based regulation systems and benchmarking;
4. Regulatory clarity;
5. Efficient rate designs;
6. Low-income electric assistance;
7. Retail choice (See Chapter 2 for additional information Retail Choice);
8. Public-private partnerships to secure low-cost electric supplies;
9. Utility consolidations;
10. Buy down of QF contracts.

Chapter 8 deals with the first step at length, while Chapter 9 includes discussion of the second step. The remainder of this chapter will examine each of the other remaining categories.

ALTERNATIVE OR PERFORMANCE-BASED REGULATION

Alternative regulation has been implemented in a number of other states and has been considered in Vermont. It replaces the traditional cost-of-service regulatory framework discussed previously with one based on operational benchmarks and specific utility performance. As a result, alternative regulation is often referred to as Performance-Based Regulation (PBR.)

Historically, Cost-of-Service/Rate-of-Return (COS/ROR) regulation has been criticized for its focus on cost and return on invested capital. Setting rates based on costs can cause a distortion in a utility's use of capital and labor and generally leads to inefficient behavior.[2] Poor rewards for incremental managerial effort also result in resource inefficiencies. PBR has long been of interest because can provide incentives similar to those of the competitive marketplace and can provide utilities with a greater incentive to make productivity-improving actions, and greater ability to price flexibly and reduce regulatory costs. Also it is generally recognized that the allocation of utility common costs under COS/ROR becomes more complicated as the number of competitive services increases. PBR can simplify the process of setting rates for the remaining monopoly services. Even though Vermont's electric utilities are vertically integrated regulated monopolies, for most electric services delivered today, they may be subject to market reforms and greater competition in the future. Such reforms and potential competitive exposure increase the importance of efficient performance by utilities before reforms arrive and because of this, PBR can act as a bridge between traditional regulation and market reform.

PBR typically decouples prices from costs during a defined period. This is accomplished by setting rates based on costs at the onset of a plan or defined period, and employing external cost-performance proxies (usually expressed as some measure of inflation and productivity offset) for the purposes of setting rates. PBR mechanisms are developed with recognition of the information asymmetry between regulators and regulated utilities. Information can be expensive and resource intensive to acquire. It is, however, integral to the traditional cost-based approach to setting rates. PBR, in contrast, places an emphasis on "light-handed" ratemaking methods that improve performance without excessive regulatory oversight.

PBR can strengthen a utility's financial incentives to lower rates or costs relative to traditional regulation and weakens the link between a utility's regulated prices and its costs. In the United Kingdom (U.K.), for example, incentive regulation has been adopted for various types of public utilities, including electricity and natural gas distribution companies, water companies, and airports. In the U.S., comprehensive incentive regulation has made the greatest inroads in the telecommunications industry. For electric utilities, rate incentives were initially limited to ones that targeted fuel purchases or the performance of individual power plants.

POTENTIAL BENEFITS OF PBR

Improved Resource Efficiency.

Resource efficiency refers to the ability of a producer to vary factor inputs (labor, capital, and materials) to reduce or minimize total cost. Resource efficiency is traditionally measured in terms of productivity. PBR typically strengthens incentives for greater improvements in productivity.

Reduced Administrative and Regulatory Costs.

Under traditional COS/ROR regulation, regulators expend considerable effort and expense to provide regulatory services necessary to protect consumers, with costs ultimately borne by those consumers. This can be a resource and an information intensive exercise. Properly designed, a PBR plan can

[2] This distortion is commonly known as the Averch-Johnson (A-J) effect.

greatly reduce the burden of regulation on both the provider and the regulator. Often, however, the burden is shifted to the onset of a new PBR plan. The recurring costs of regulation are typically reduced once the plan is in place.

Improved Allocative Efficiency.

Allocative efficiency is achieved when an economy adjusts output to maximize total value and improves when prices for goods and services approach the underlying marginal cost. PBR, combined with pricing flexibility, can improve utilization of existing assets or capacity holdings as it can provide the incentives, tools, and flexibility to retain customers and loads with more elasticity (the more price sensitive loads).

BENCHMARKING

Benchmarking compares financial and operating matrices and indexes of comparable companies, to highlight or identify differences. It can be used effectively either as an integral part of PBR or in conjunction with traditional cost-based regulation. When these financial and operational differences are analyzed and examined, “Best Practices” emerge that can guide companies in changing their processes or adopting new perspectives that lead to overall cost reductions and improvements in efficiency. Benchmarking can and should be more widely used in Vermont to stimulate the identification and adoption of “Best Practices”, and ideally, to stimulate better service at lower prices.

GENERAL PBR FORMATS

Price Caps

Price caps are a “price ceiling” or a pre-set price that cannot be exceeded by the utility. Under these caps, prices for monopoly utility services are set for long periods of time without regard to the utility’s costs. Rate freezes or significant regulatory lag, both forms of COS/ROR regulation, may be viewed as forms of price caps, which are often indexed over time using the formula commonly known as the “consumer price index (CPI) minus X” formula. This formula sets prices each year as a function of the previous year’s prices, inflation (I) and a productivity offset (X). CPI minus X has been widely applied as an incentive regulation formula in the U.S. and U.K. telecommunications industries.

Revenue Caps

Under revenue caps, a regulator caps a utility’s allowed revenues with an external index. Subject to this cap, the utility is permitted to maximize its profit margin presumably through cost containment. Most revenue caps are applied to revenues deriving from base rates only. Although base-rate revenues are generally considered fixed with respect to the level of per-customer sales, revenue caps usually allow some adjustment for increases in the number of customers. A variation of the revenue cap allows revenues to increase in direct proportion to the number of customers. Revenue caps can be combined with earnings sharing mechanisms to guard against the possible failure of the index to keep returns within acceptable bounds.

Earnings Sharing Mechanisms

PBR plans often rely on external indexing of rates or revenues. Most indices use an inflation index and adjust it for expected or desirable changes in productivity. Inflation indices and productivity offsets should be evaluated jointly because their combined effect determines overall performance. Earnings sharing mechanisms track actual earnings, sharing with ratepayers any earnings that fall above certain thresholds. They may be the defining aspect of a PBR plan or they may supplement a price or revenue cap plan. Earnings sharing mechanisms and earnings limits represent a departure from COS/ROR ratemaking, which usually provides that utilities retain all deviations in earnings between rate cases. Plans often include "dead bands" where shareholders are at risk or face the opportunity to capture all or most earnings fluctuations.

Alternative Regulation of Publicly Owned Utilities

As noted in Chapter 2, Vermont is one of the few states that provides for regulatory oversight of publicly-owned utilities such as municipal utilities and cooperatives.

State regulators and public utilities should explore ways of relying on the inherent strength of existing voter systems to supplement traditional regulatory review, especially where the ratepayer interests are well aligned, or can be aligned, with voter interests. The fundamental objective here, however, is to ensure ratepayers are assured adequate protection at fair prices. Alternative regulation, whether developed in conjunction with an IOU or a customer-owned system must demonstrate discernable ratepayer benefit.

SUMMARY

Both COS/ROR and PBR have certain limitations and advantages. This section highlighted areas where PBR compares or is generally acknowledged to compare favorably to traditional cost-of service regulation. Nevertheless, PBR has its limitations as well, for example with greater freedom and flexibility, typically comes both opportunity and risk to shareholders. In certain cases, PBR can be used to help shield the utility from a particular risk, such as wholesale energy price volatility. The design of an appropriate PBR plan to reflect the proper mix between ratepayer and shareholder/owner risk and reward can be a complex undertaking. Nevertheless, opportunity exists for better and more efficient service delivery through alternative forms of regulation and these should be explored with a focus on reducing rates through improved efficiency. Governor James Douglas signed Act 69, effective June 2003 that included enabling language for alternative regulation plans. In 2003 and 2004, the Department of Public Service (DPS) has been working with Vermont Gas on an alternative regulation plan; the first for Vermont outside the telecommunications sector.

REGULATORY CLARITY

Regulatory risk can be simply defined as a measure of the degree of regulatory consistency and predictability that exists within the local, state, and federal regulatory environment. Where there is uncertainty regarding consistency and predictability about the decisions a regulator may make, one of the major risks associated with that uncertainty is the possibility that an expense or an investment might be found to be non-recoverable in rates. A lack of perceived regulatory consistency and predictability has the potential for a significant negative impact on a regulated entity's cost of capital.

The world's three major credit rating agencies, Fitch, Standard & Poor's, and Moody's, use a variety of techniques to rank the riskiness of companies. Those rankings determine the rates at which utilities can borrow money and the degree to which they can issue debt. Entities performing credit ratings base their analysis on a wide range of factors, both qualitative and quantitative, to assess the probability of default. Typically these include debt management history, debt equity ratios, and current and forecasted cash balances. Consequently, they are closely examining utilities and looking for anything that might put too much strain on cash flows.

Regulation is typically a component of the risk evaluation. Utility companies' economics depend heavily on the policy decisions of state regulators. The framework of regulatory decision-making has very significant comparative impacts on those companies' access to, and cost of capital. Therefore, perceived regulatory clarity, while not the only factor, is an important one in determining the costs of Vermont's electric supply.

The cost of utilities' access to capital matters because the electric utility business is capital-intensive and requires large amounts of cash for long-lived generation, transmission, and distribution facilities. Investor-owned utilities can raise cash by issuing a combination of debt (bonds) and equity (stock) while publicly owned utilities can only issue debt. The expected return on both debt and equity that must be offered to investors depends on the risk of each. For example, "junk" bonds—which are below investment grade—have a higher risk of default than do U.S. Treasury bonds. As a result, the expected yield on junk bonds, which have a higher probability of default, are higher than the yield on Treasury bonds, which have no default risk whatsoever. The U.S. electric utility business is commonly known to be the most capital intensive of the major industries in the economy. This means that, per dollar of revenue, electric utilities invest relatively more dollars in long-term plant and equipment than do other businesses. Vermont's utilities currently have well over half a billion dollars of investment reflected on their collective balance sheets. As such, the prices charged by the financiers who supply capital that fund utility investment, has a major influence on the overall cost of providing electric service and, therefore, on the prices consumers pay for power in Vermont. Credit status also impacts the terms that the suppliers of other inputs offer Vermont's utilities and influences the cost of items such as purchased power.

The need for clarity has heightened importance now, at a time when industry participants have been roiled by unprecedented financial disruptions and failures, and by persistent uncertainties elsewhere in the public policy arena. Investors and company leaders are currently wrestling with a variety of fundamental uncertainties: state-by-state changes in policies related to industry restructuring; purchased power contract disputes, as in California; accounting standards revisions related to energy purchasing, trading and hedging activities; uncertainty over aspects of currently pending energy legislation such as PUHCA reform; Federal Energy Regulatory Commission (FERC) transmission policy, transmission siting rules, and transmission-related tax policy on transfers in ownership; and certain aspects of bankruptcy code reform, just to name a few.

For Vermont utilities, major long-term power supply agreements are scheduled to terminate over the next decade. As such, the credit status of the utilities can be expected to have significant affect on the utilities' abilities to purchase replacement supplies.[3] Vermont utilities also rely on the region's spot

[3] This is of heightened importance in light of the collapse of ENRON and the recent insolvency of other wholesale power market participants (USGen New England, Inc.). As a result, counterparties, including the ISO, now place great emphasis on a purchaser's credit status when considering the need for and amount of security to be required in connection with a power supply arrangement. If Vermont utilities are viewed as too financially weak to support a proposed power supply arrangement, counterparties will not transact business with Vermont or will do so only on terms that limit the seller's risk in the transaction.

wholesale power markets for hour-to-hour purchases and sales needed to balance load and supply in Real Time (RT). The credit status of Vermont's utilities directly affects the ability, and cost incurred by, the utilities in transacting with counterparties for the power needed by consumers in the short term as well. The cost of major upcoming transmission investments and ongoing distribution network investments will also be affected by the credit status of Vermont utilities.

Vermont's regulators can help control the level of regulatory risk by bringing sufficient clarity to the regulatory treatment of a number of issues that changing markets require. These include clarity as to appropriate levels of supply and price hedging by utilities, consideration of market price adjustment clauses, and sufficient clarity regarding principles for determining the prudence of utility expenses and investments.

EFFICIENT RATE DESIGNS

The rates utilities charge matter to individuals and businesses, not only because they directly affect their overall electric bills, but also because they affect decisions that can or will change consumption. The cost and efficiency with which service can be delivered can be controlled through (1) a continued emphasis on cost-causation in defining and establishing a fair and efficient rates, (2) more emphasis on formal tariffing elements currently delivered through special contracts that are not actually special or unique in character, (3) the ongoing need to continue to explore innovative rate design to better capture underlying cost drivers that are increasingly volatile and uncertain.

A long-standing principle of electric utility ratemaking is ensuring that rates capture appropriate underlying cost drivers. Efficiency and fairness argue for continued emphasis and vigor in applying the principles in a regulated environment. As Vermont utilities look forward, the accounting for costs may need to ensure that elements of cost that may ultimately be attributable to competitive conditions can be appropriately isolated for monopoly services.

Vermont currently relies heavily on special contracts to further, on a case-by-case basis, the economic development interests of the state and to ensure efficient interruptions of customers capable of interrupting service for the benefit of the utility and remaining customers. Special contracts of this nature, however, run the risk of undue discrimination, while increasing the burden of regulation on customers, operators and regulators. Every effort should be made to standardize and tariff common features of electric rates currently reflected in special contracts. The Department also needs to work with the Public Service Board to ensure transparent rules for residual elements of special contracts to further reduce the customer and regulatory burden of current special contracts.

Changes in the nature of wholesale markets and the ensuing dependence on natural gas has increased Vermont's exposure to volatile wholesale prices. Innovations in metering, telemetry, and smarter end-use applications are enabling new opportunities for cost-effective and innovative rate design. Vermont should continue to explore opportunities created for innovative rate designs that provide clear price signals for efficient use and/or interruption of electricity consumption. Customers that participate in such programs should be provided some share of the value of program participation through system benefits.

Efficient rate design also means that the rates should reflect the underlying character of costs. Recurring fixed costs should be reflected in fixed monthly charges. Incremental charges should also reflect the long run marginal cost of each kWh.

In summary, rate design strategy should be focused upon the assignment of costs on the basis of cost causality and designing rates that encourage ratepayers to consume electricity in economically efficient ways.

LOW-INCOME ELECTRICITY ASSISTANCE

SCOPE OF THE PROBLEM

The impact of Vermont's high electricity prices is especially great on people with low incomes because home energy as a whole presents a crippling financial burden. A recent study of energy affordability in the U.S.[4] examines the gap between affordable energy bills and actual bills of low-income households. Affordability for the total energy burden is defined as 6% or less of total household income while heating alone is defined as 2% of total household income.[5] The affordability gap study looked at the burden on low-income citizens by county and state throughout the U.S. Vermont ranked 50th in affordability (among the states and the District of Columbia) for all low-income consumers and 51st for Vermonters with household incomes below 50% of the federal poverty standard.

Vermonters whose household income is at or below 185% of the federal poverty standard carry an energy burden that averages $1,170 more than the level that is affordable. The 8,600 or so Vermont households at the lowest income levels below 50% of the federal poverty standard B spend 61.3% of household income on energy.

The Low Income Heating Energy Assistance Program, or LIHEAP, provides some assistance during the winter months to assist Vermonters in paying their heating bills, but the amount of funding falls far short of meeting the need. In the 2001 and 2002 heating season, actual energy bills of low income Vermonters exceeded affordability (6% of household income) by $67 million. In the same season, low-income energy assistance totaled $9.9 million. Price increases and severe weather in 2002/2003 most likely increased the affordability gap even further.

The main LIHEAP fuel assistance program in Vermont is limited to payment for heating fuel. Since less than 5% of Vermonters heat with electricity, the effect is that little or no assistance is available for electricity, apart from the WARMTH and Share Heat programs, which are funded from voluntary contributions by utility customers. The crisis fuel assistance program can be used to pay electric bills

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[4]On the Brink: The Home Energy Affordability Gap, Fisher Sheehan and Colton Public Finance and General Economics, Belmont, MA, May 2003.
[5]The affordability thresholds are based upon HUD assumptions that total shelter costs should not exceed 30% of income, and energy costs should not exceed 20% of total shelter costs. Residential Energy Consumption Data shows that heating costs represents about one third of total energy costs. E-mail communication between the DPS and Roger Colton, 5/6/04.

only for those consumers who have received a disconnection notice. No stable source of assistance is available for electric bills on the basis of financial need.

The consequences of unaffordable energy bills are serious. A recent study commissioned by the National Energy Assistance Directors' Association (NEADA) quantified severe negative impacts of the affordability gap.[6] Health impacts included 22% of LIHEAP recipients reporting they went without food for at least one day, 38% without medical or dental care, and 30% without filling a prescription or taking the full dose prescribed. 21% got sick because their homes were too cold. The impacts on shelter were also severe, with 28% failing to make a rent or mortgage payment, 9% reporting they moved in with family and friends, 4% experiencing eviction and 4% becoming homeless.

Trends in disconnection rates by Vermont electric companies show the increasing impact of unaffordability on low income Vermonters. Under PSB rules, residential consumers are subject to disconnection when their accounts are delinquent, which means the bill is unpaid 30 days after the mailing date. The rules provide various opportunities for consumers with delinquent accounts to enter into payment arrangements, or produce a doctor's note indicating disconnection will present an "immediate and serious health hazard" to forestall disconnection. In addition, winter temperature restrictions prevent disconnection when the temperature is forecast to drop below 10 degrees or 32 degrees for households that include seniors. The various protections in the rules mean that, as a practical matter, consumers have had multiple months of delinquency before they are actually disconnected. The payment protections in the rules serve in effect as a safety net to protect vulnerable people from the loss of electricity. Shut-off protections such as those in the Vermont rules are a common way of protecting low-income consumers, and are incorporated in some form into the rules of most states. This approach, however, has significant costs for utilities and their ratepayers in terms of collections expenses, arrearages, and write-offs. These are hidden costs are borne by all ratepayers in the form of higher rates. Table 10-1 shows that the rates of residential disconnection per 1,000 customers have been raising steadily since 1998. The increasing disconnection rate reflects the growing affordability gap.

[6] National Energy Assistance Survey Report, Prepared by APPRISE for the National Energy Assistance Directors' Association, April 2004.

TABLE 10-1 ELECTRIC UTILITY DISCONNECTION RATES, 1998 AND 2000-2003					
	Disconnections per 1000/residential customers				
Company	**1998**	**2000**	**2001**	**2002**	**2003**
Barton Village	NA	14.7	18.5	25.6	30.2
Burlington Electric	NA	38.5	45.0	46.7	50.9
Central VT Public Service	19.4	24.7	20.0	20.6	29.9
Citizens Utilities	NA	42.2	27.2	41.5	49.3
Enosburg Falls	61.1	49.5	66.3	45.5	54.3
Green Mountain Power	18.0	12.9	28.8	34.3	41.2
Hardwick	13.6	18.8	24.5	25.2	11.6
Hyde Park	11.0	17.4	31.9	18.2	20.8
Jacksonville	8.6	1.7	6.3	NA	NA
Johnson	NA	52.0	31.4	24.1	NA
Ludlow	1.4	3.1	1.4	0.7	5.2
Lyndonville	14.0	23.2	17.3	12.1	47.2
Morrisville	10.5	16.8	19.5	22.2	23.4
Northfield	50.0	39.5	32.4	35.9	42.2
Orleans	NA	1.6	5.9	3.0	1.6
Readsboro	NA	0.0	0.0	6.3	7.5
Rochester	5.0	5.8	17.1	15.7	11.4
Stowe	NA	NA	0.6	5.2	16.0
Swanton	16.1	28.2	30.8	25.6	26.9
VT Electric Cooperative	22.4	4.0	29.7	53.1	39.7
VT Marble	2.5	NA	9.1	4.5	NA
Washington Electric Coop	NA	9.4	11.2	10.9	11.6
Weighted Statewide Average	18.9	21.6	25.8	27.5	34.6
NA indicates that the data are unavailable.					

APPROACHES TO LOW INCOME ASSISTANCE

In addition to LIHEAP and weatherization, many states provide assistance to low-income consumers to reduce the burden of their electric bills. At least 32 states have some form of specific low-income electric energy assistance. Twenty-three of these states have electric industry competition. In all but six of these states, electric bill assistance existed prior to industry restructuring.[7] At least nine states that are not open to electric competition have some form of ratepayer or taxpayer funded program to assist low-income consumers with their bills.

Many models of low-income energy assistance exist around the country. In a paper entitled, "Models of low-income utility rates,"[8] Roger Colton reports the following approaches to low-income programs funded on a non-voluntary basis either through rates, surcharges or taxes:

- Straight rate discount—across-the-board, percentage discount to income-eligible households.
- Income-based rate discount—variable percentage discount based on each household's percentage of poverty level.
- Marginal cost-based rate—rates set to explicitly recover costs of service plus some contribution to fixed system costs.
- Available resource approach—rates set based on the household's disposable income after other household expenses are paid.
- Percentage of income payment plan—energy bills set equal to a percentage of household income (seeking to reduce bills to a level defined as "affordable").
- Waiver of fixed monthly customer charge.
- Inverted block rate—rates increase in unit cost in blocks or tiers as power use increases.
- Direct vendor payments—earmarking of specific public benefits, such as a portion of public welfare, to direct utility payments.
- Usage-based discounts.

Funding approaches vary among the program types and among the states. The three major categories of funding options include:

- Building discounted low-income rates into utilities' rate structures. Such an approach was proposed by Central Vermont Public Service (CVPS) and Burlington Electric Department (BED) in the early 1990s, and the PSB determined it could not be done under current Vermont law.
- A surcharge on all or some bills. Such a surcharge may be either fixed or be a percentage of bills, as in the case of the Vermont Universal Service Fund for telecommunications and Vermont's Energy Efficiency Surcharge. This approach is sometimes called a system benefit charge.
- Appropriation of general revenue or other public support for program funding.

[7]"Other states' low-income energy assistance programs and electric utility restructuring," Virginia Commission on Electric Industry Restructuring, http://dls.state.va.us/groups/elecutil/cab/othrstts.htm, September 14, 200.

[8]"Models of low-income utility rates," Roger D. Colton, Fisher, Sheehan & Colton Public Finance and General Economics, Belmont, MA, June 1995.

PERCENTAGE OF INCOME MODEL DISCUSSION

In the last several years, Percentage of Income Payment Plan (PIPP) has become the preferred model of low-income electric assistance for many states.[9] A PIPP sets energy bills equal to a percentage of household income. A household is eligible for the program if its income meets eligibility guidelines and its annual energy bill is at or above the threshold percent of household income. Thus if the total bill is already below the affordability threshold (less than X percent of household income), the consumer is ineligible, even though the household is income-eligible.

The New Hampshire Electric Assistance Program provides an example of a PIPP. The program operates as follows by using 4% of household income as its standard of electric affordability for base load customers and 6% of household income for space heating customers. Low-income consumers are placed into tiers by eight annual income ranges. The midpoint of each range (for $2,000-$3,999, it is $3,000) is used to calculate the affordable electric burden for that range. Thus the affordable annual bill for a household in the $2,000-$3,999 income range would be 4% times $3,000 or $120. The amount of annual benefit is determined by the difference between the affordable bill and the average annual residential bill. A System Benefit Charge (SBC) levied on all bills funds the program. Program eligibility determination is contracted to the New Hampshire Community Action Agencies.

New Hampshire originally selected a slightly different model of PIPP called a fixed-benefit payment plan. This model calculates the discount amount based on actual income and actual usage of each individual household, in contrast with the tiered-discount approach, which uses ranges of income and average residential usage. Although the fixed-benefit approach is closely calibrated to ensure each household's bills are reduced to the affordability standard, the administrative and set-up costs of the fixed-benefit program were so much greater than the tiered-discount design that the Commission ultimately chose the more efficient and less precise model.

SAVINGS FROM LOW-INCOME PROGRAMS

Although lack of affordability of electric rates is a social problem, it is also a utility problem that poses significant costs that are ultimately recovered in the form of higher rates. A 1991 study detailed eight areas of utility costs associated with unaffordable bills.[10] It concluded that, when disconnection is used as a collections device, the cost of disconnection and reconnection of a single household in 1989 was $65.71-$66.99 (depending upon specific collections activities). Other costs associated with energy unaffordability include bad debt, deposit maintenance expenses, regulatory costs associated with handling complaints, customer service time spent in negotiating payment arrangements, credit agency fees, and the lost time value of arrearages. In addition, when households are able to pay their electric bills, they avoid the diverted revenue associated with debt collection (such as reconnection fees) and the forced mobility, leaving more money available for electric bills.

The ability of low-income energy assistance programs to reduce collections and related costs has recently been demonstrated by a study commissioned by the Colorado Energy Assistance

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[9]The article cited in footnote 4 discusses the pros and cons of all the listed models.
[10]"Identifying savings arising from low-income programs," Roger D. Colton, Fisher Sheehan & Colton Public Finance and General Economics, Belmont, MA, July 1994.

Foundation.[11] Among the findings were reductions of 35% to 70% in arrears and 65% to 80% in disconnections. The potential for savings by utilities from the availability of a low-income electric energy program is one reason why utilities have often advocated for the establishment of such programs through rate design.

- The potential benefits of helping Vermonters with low incomes pay their electric bills and avoid the costs of disconnection merit further consideration. A reasonable next step would be for the state to work with utilities to more completely identify all current utility costs associated with unaffordable bills for low-income consumers. This cost study should consider all cost impacts in order to identify the full potential benefits of a low-income electric assistance program. This information could help inform a study committee composed of utility representatives, low-income advocates, and regulators who should thoroughly review available models and develop a cost-benefit analysis of at least one model for a low-income electric energy assistance program in Vermont. The results of that study should be used to guide public policy on the establishment of such a program.

RETAIL CHOICE

As was discussed in Chapter 2, retail electric choice was considered, but never adopted in Vermont. Debate continues over whether Retail Choice remains a viable option for the future. One of the key barriers to retail choice may disappear in the future with resolution of stranded costs. The bulk of Vermont's stranded costs arise from contractual commitments with HQ and the Independent Power Producers (IPP). A lesser portion was the Vermont utilities' ownership of VY. This issue has been resolved by the sale to Entergy. With the termination date of the IPP contracts approaching and the HQ contracts ramping down (2010–2012) another impediment to choice may be eroding.

More fundamental than the concerns over stranded costs is the question of whether retail choice represents a desirable path. As noted in prior discussion, the retail choice experiment in at least one state proved a failure. Hard lessons can be learned from other states, and positive lessons from others. The New England wholesale market administered by ISO-NE continues to struggle with mechanisms that effectively replicate resource deployment under a fully integrated regulated system. The ultimate questions to answer in considering deregulation is to assess the best way to deliver competitively priced, reliable electricity for Vermont ratepayers that is also consistent with long held Vermont values. A limited review of rates in Vermont relative to those state's that have moved forward with retail choice, yields little basis for drawing clear conclusions about impacts one way or another.[12] Rate impacts are, however, only one dimension of a broader analysis. Vermont can benefit by simply remaining an objective observer of the experience in neighboring states and the nation.

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[11] *The economic impacts of home energy assistance in Colorado*, Roger D. Colton, Fisher Sheehan & Colton Public Finance and General Economics, Belmont, MA, February 2003.

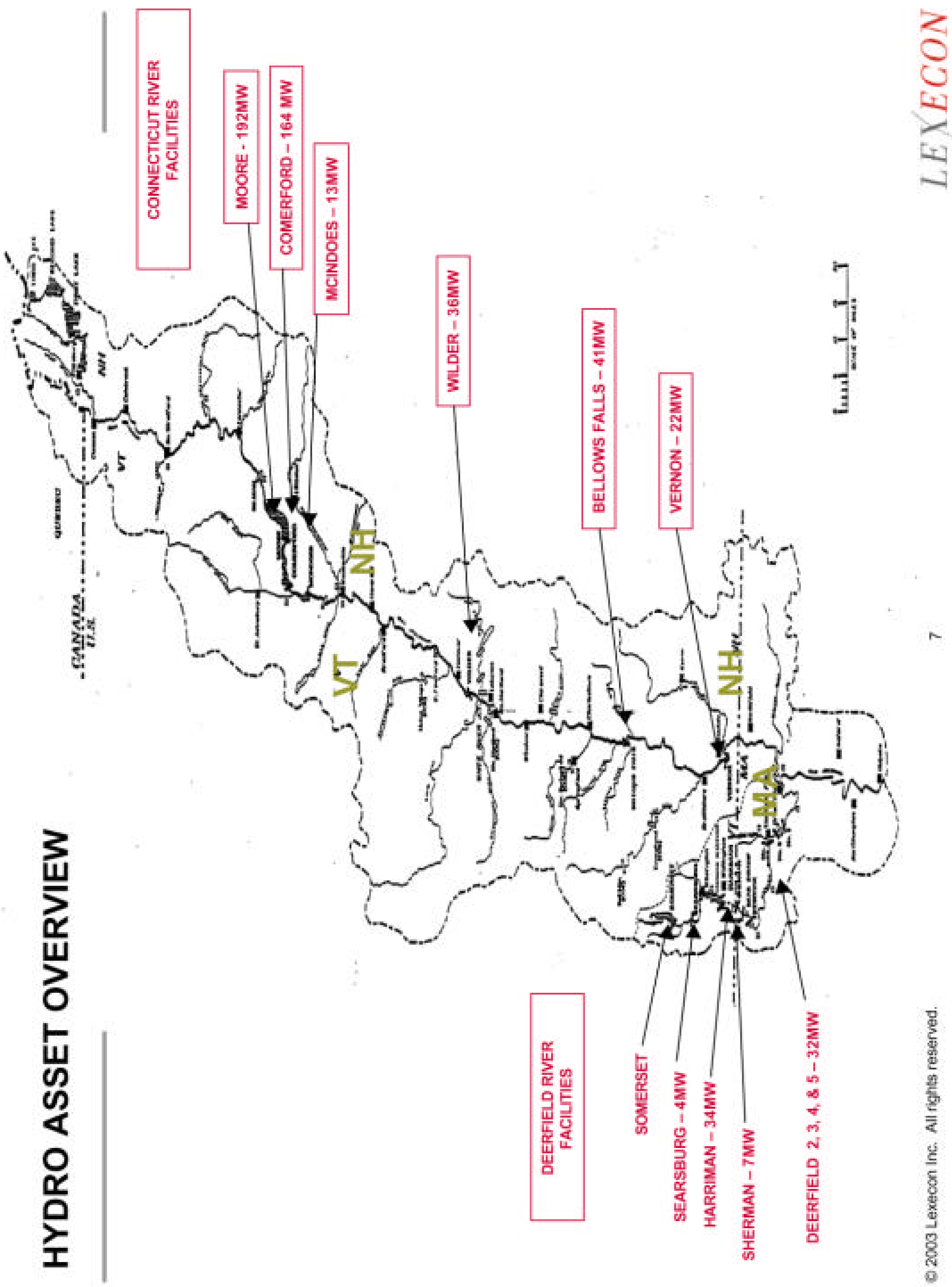
[12] Given the current high wholesale market prices and likely greater exposure to those prices in restructured markets, one would expect restructured states to have experienced higher prices.

PUBLIC-PRIVATE PARTNERSHIPS

THE CONNECTICUT RIVER HYDRO OPPORTUNITY

The July 2003 bankruptcy filing of U.S. Generating Company (USGen) and its parent company, Bethesda, Maryland.-based PG&E National Energy Group, created a potential opportunity for Vermont. In 1998, USGen paid about $1.8 billion to the New England Electric System for a number of dams on the Connecticut and Deerfield Rivers, as well as several other generating assets, according to documents filed with the Securities Exchange Commission. Those assets include several hydroelectric plants located on the Connecticut and Deerfield rivers. Together, the Connecticut River dams, located partially in Vermont and partially in New Hampshire are rated at 468 MegaWatts (MW), while the two Deerfield River dams, located entirely in Vermont are rated at 38 MW, therefore totaling over 506 MW of hydroelectric generating capacity for the Vermont based portion of the portfolio.

Figure 10-1


HYDRO ASSET OVERVIEW
CONNECTICUT RIVER FACILITIES
MOORE - 192MW
COMERFORD – 164 MW
MCINDOES – 13MW
WILDER – 36MW
BELLOWS FALLS – 41MW
VERNON – 22MW
DEERFIELD RIVER FACILITIES
SOMERSET
SEARSBURG – 4MW
HARRIMAN – 34MW
SHERMAN – 7MW
DEERFIELD 2, 3, 4, & 5 – 32MW
CANADA
U.S.
VT
NH
VT
NH
MA
LEXECON
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Recognizing this as a potential opportunity to purchase a secure, long-term, and environmentally friendly generating resource, the Legislature formed the Vermont Renewable Power Supply Acquisition Authority to evaluate the pros and cons of Vermont participating in an auction of the dams and allocated $250,000 to study the feasibility of purchasing the dams. In the summer of 2003, the Authority hired a consulting firm, Lexecon, to evaluate the feasibility of Vermont's participation in an auction.

Lexecon found that, while Vermont would have only a 7.5% chance of success should it bid on the dams alone, it could enter into a partnership with a private company and thereby gain, assuming a successful bid, access to a portion of the energy produced by these facilities. If such a bid were successful, Vermont would be able to make available stable, clean, renewable power to its retail utilities. Going north to south, the six Connecticut River dams are the Moore Station and Dam in Waterford, the biggest power producer of the group, the McIndoes and Comerford stations in Barnet, the Wilder station, the Bellows Falls Station in Rockingham, and the Vernon Station in Whitingham. A deal would also include the Searsburg and Harriman stations on the Deerfield River, which are just north of the Vermont border with Massachusetts, and the Sherman and Deerfield 2, 3, 4 and 5 units in Massachusetts.

In the Spring of 2004, Vermont chose to join two private investors, Emera Energy, based in Nova Scotia and Brascan Corporation of Toronto, which specializes in developing energy projects in Canada and the U.S. Emera is also the parent company of Nova Scotia Power and Bangor Hydroelectric. If a bid were successful, the Vermont Hydroelectric Power Authority, a quasi-public authority would own and manage the State's interest. In the case of the dams, the money made from generating electricity would be used to repay the bonds.

The 2004 General Assembly took the next step necessary to move the process forward and created the Vermont Hydroelectric Power Authority ("VHPA"), an entity with the powers to issue bonds, and to own, operate and manage any interest the VHPA may acquire in the facilities. (The VRPSAA did not have these powers.)

Extensive analysis and strategic planning took place between June and September. Lexecon refined the economic model to determine a fair and economically efficient price for the facilities. The VHPA hired a financial advisor (using a competitive bidding process) to determine the financial market requirements for raising funds, to assist in thinking creatively about financing options, and to negotiate joint financing packages with Brascan and Emera.

Governor Douglas appointed a Board of Directors on August 17, 2004. By statute it included the State Treasurer, Jeb Spaulding and an appointment by the Public Service Commission, who took the seat himself. The Governor appointed four of the five remaining seats: Brad Aldrich, Nancy Brock, Richard Mallary, and Fred Tiballi. The first Board meeting took place on September 27, 2004 at which time Brad Aldrich was elected Chair, and Jeb Spaulding Vice Chair.

USGen and the bankruptcy creditor's committee hired an investment-banking firm, Lazard Freres & Co., to determine interest in all of USGen's assets (including the hydro's and three fossil-fuel fired plants), with a goal of maximizing value for the creditors. There was an initial due diligence period during which all interested parties were given several months to do extensive investigation into the system's condition and operations, followed by a confidential round of bidding. Sixteen bids were submitted in that round (a figure made public in later bankruptcy court filings). From those bids, TransCanada Hydro Northeast Inc's $505 million offer was chosen as the leading bid for the next round.

The bankruptcy auction process took place in December 2004, with a minimum next bid of $527,750,000 (this figure included court-approved breakup fees and expenses for TransCanada and an additional $5 million increment). After extensive analysis, the partnership of VHPA, Brascan and Emera concluded that at $528 million or more, the investment would not offer sufficient returns. The partnership therefore did not bid in the auction.

While VHPA was not seeking a "return on investment" in the commercial sense, its was necessary that there be real value to Vermont flowing from any acquisition. The VHPA's financial analysis showed that, in order to cover its financing and operating costs, the power controlled and sold by the VHPA would have to be priced above the current market price, and would likely continue to be above market based on the forecasts. The VHPA would also need long-term commitments from wholesale power purchasers to buy at the above-market prices in order to secure bond financing.

The VHPA, and all the bidders, were involved in a very competitive process for an attractive set of assets. The auction produc ed a bid at full value. It is telling that no entity bid against TransCanada at the public auction. While the project could have yielded significant value for Vermont and its electricity customers at the right price, the bid price meant that this was not an opportunity for low cost power for Vermont customers. In the end, the price was just too high.

EXPLORING THE BENEFITS OF OTHER PUBLIC-PRIVATE PARTNERSHIPS

The potential acquisition by Vermont of a share of the Connecticut River hydroelectric dams is only one example of a public-private partnership that may help reduce overall electrical costs. There may be other opportunities for such partnerships that can foster additional in-state renewable resource development and provide accompanying economic benefits. There could be other benefits, by fostering development of generating resources, such as agricultural waste-to-energy facilities, and in so doing address other environmental problems facing the state. Other potential benefits include industrial development through favorable power sale arrangements or indirect support mechanisms like power price offsets, and additional price hedging opportunities.

Public-private partnership opportunities should be identified wherever possible. Of course, this does not mean that Vermont should enter into such partnerships at any opportunity as the costs and the benefits of any partnership must be thoroughly analyzed by first identifying clear objectives for any new partnership. These goals should be consistent with the general good of Vermont and should not come at the expense of individual Vermonters, much as electric rates are designed to avoid unfair cross-subsidies between different customer classes. Specific goals associated with these objectives should be identified and critical parameters of the opportunity to reach those goals evaluated. For example, if the objectives of state-owned waste-to-energy facilities were lower electric costs and reduced water pollution from agricultural runoff, specific goals (10% reduction in each) should be defined. Once such goals are identified, the ability of the partnership opportunity to reach them, and the downside risks, if any, could then be carefully evaluated.

CONSOLIDATION OF UTILITIES AND/OR SERVICE TERRITORIES

Vermont is currently served by four relatively large electric utilities and 17 smaller utilities. The number of utilities has recently been reduced through consolidation. In 2003, Vermont Electric Cooperative (VEC) agreed to purchase Citizens Communications Company—Vermont Electric Division (VED). VED had been the subject of much oversight because of a number of accounting irregularities and disregard of the PSB Orders. The parent company has been restructuring itself to focus solely on telecommunications and has been divesting its electric, gas, and water utility divisions for a number of years. The PSB approval of the sale of VED to VEC was completed in the first half of 2004, and promises savings to ratepayers through consolidation of operations, coordinated distribution system planning, and improved reliability.

The potential for economies of scale raises the question of whether it would be less expensive and/or improved electric service in Vermont could result if there were fewer separate utilities. Continued consolidation of both large and small companies, or opportunities for shared service capacities, to achieve competitive economies of scale, may be desirable over this 20-year planning period.

Small utilities have played an important role in the development of Vermont's rural communities. They typically have responded to the local community's needs for service in a manner that reflected the characteristics of the local community, the customers, and territories they have served. High electricity rates have raised questions and concerns about the Vermont's utility composition, specifically whether a small state can continue to absorb the additional costs associated with so many utilities.

To date, while consolidation has been discussed, no formal studies of the costs and benefits of consolidation have been performed. Without more empirical evidence, the extent of the value of consolidation cannot be fully gauged or appreciated. Further study of the issue appears warranted.

SECURITIZATION OF QUALIFYING FACILITY POWER

In the 2001 session, the Legislature passed a bill authorizing securitization that is a financial tool whereby contracts can be bought out or bought down to a lower, more reasonable level. Under this approach, Vermont or some other bonding authority would issue bonds, the proceeds of which would be paid to producers in return for lower rates. Since Vermont is issuing the bonds, very favorable bond rates will result in substantial savings relative to current QF price levels.

The potential savings from successful buy downs of the existing agreements could be substantial, especially in an environment of low interest rates. The amount of potential savings from contract buy downs is time sensitive and the available benefit decreases with the passage of time. State regulators should ensure that QF owners fulfill commitments to work toward the buy down of existing contracts through securitization.

RECOMMENDATIONS

There are no easy solutions to reducing what Vermont residents and businesses pay for electricity. Vermont exists within a region with high wholesale electricity costs. Wholesale electricity accounts for the dominant share of the electric rate. As a rural state with a dispersed population, Vermont is also at a comparative disadvantage with respect to the wires component of the electric rate. There are, however, a number of steps that the state can explore or begin to implement so that electric energy prices are less of a barrier to economic development, those with low incomes face fewer problems paying their bill each month, and all ratepayers enjoy the benefits of more affordable electricity. As discussed above in this chapter, these include:

- Vermont utilities and regulators should begin designing and implementing alternative, performance-based regulation to encourage superior performance for consumers.
- Vermont regulators must consider the perception of regulatory clarity in this State.
- Vermont utilities must adopt and implement efficient rate designs that reduce the costs of and promote business expansion decisions to encourage economic growth within the state.
- The DPS should examine, cooperatively with Vermont utilities, current costs associated with unaffordable bills for low-income consumers. This study should consider all cost impacts in order to identify the full potential benefits of a low-income electric assistance program.
- The DPS should convene a study committee composed of utility representatives, low-income advocates and regulators to conduct a review of available models and a cost-benefit analysis of at least one model for a low-income electric energy assistance program in Vermont. The results of that study should be used to guide public policy on the establishment of such a program.
- The State should re-examine the benefits and costs of retail choice for adoption at some point in the future, especially as the current portfolio of major power supply contracts comes closer to expiration, as the experience from neighbors can be reviewed, and after the ongoing changes in the bulk power system have been fully implemented and stabilized.
- The State should promote and explore public-private partnerships.
- Undertake study on the merits of utility consolidation or other opportunities, such as shared service arrangements, to secure potentially more efficient and lower-cost operations.
- Encourage the development of a buy down of current QF contracts for power through securitization.

PRIORITIES AND ACTIONS FOR THE FUTURE

Over the next twenty years, the electric industry will continue to evolve in ways that appear likely to defy prediction. Over the short run, the industry is poised for new challenges presented by a cascade of wholesale market reforms. Ongoing policy and regulatory reforms within the region, changes in market design, and the uncertain wholesale market now predominate in a sector long understood to be stable and reasonably predictable.

Among these changes, Vermont has chosen to take a separate path in the region by maintaining a vertically integrated monopoly electric utility structure. New York and our New England neighbours have opened the sector to competitive retail choice. Even in an integrated utility environment, much of our utility costs can be subject to influence from the wholesale markets. Exposure to those market conditions will continue to affect Vermont over time as existing power cost contracts and commitments expire or are lost. Some of those forces are creating renewed upward pressure on the already high price of electricity in Vermont.

Vermont must establish strategies and actions that reflect Vermont values, while accepting the realities of change in front of us. The strategies and action plan presented below represent ways of advancing Vermont's values in the face changes and market uncertainties ahead. In light of current circumstances and the changes highlighted here, the following priorities and actions are recommended in this Plan.

PRIORITIES

RESOURCE DIVERSIFICATION

Vermont's portfolio of electric resources must become more diversified. They depend on Hydro Québec (HQ) and Vermont Yankee (VY) for two-thirds of their electricity. Electric utilities need to begin the process of planning for the replacement of those resources. This is especially important for VY, which, because of the lack of dry-cask storage capacity on site, could be forced to shut down as early as 2007. Although the HQ contracts do not begin expiring until 2012, it remains a promising and reliable source of electricity for now and for the long term. New renewable energy sources should also be encouraged, through development of comprehensive, well-designed and properly focused voluntary green pricing programs and other incentive mechanisms that offer utility customers opportunities to invest in new renewable energy developments.

LOWER COSTS FOR ELECTRIC SERVICE

In recent years, Vermont's electric energy policies have focused on reducing consumption and bills. But reducing Vermont's high electric rates is also important to foster Vermont's economic growth. By encouraging incentives for more efficient utility operations through alternative performance-based regulation systems, greater regulatory clarity, more advanced decision making tools, and new efficient rate designs that reduce the costs of business expansion decisions, Vermont can lower overall rates and encourage economic growth. Additional steps to diversify utilities energy portfolio will also reduce the potential for future price shocks.

PROMOTE CLEAN AND STABLE SOURCES

Vermont places high value on sound stewardship of the environment. For this reason, its electric plan should promote a clean source mix. Clean sources certainly include renewable technologies.

FUTURE PLANNING AND STAKEHOLDER INVOLVEMENT

The remainder of this Chapter lists specific actions to be undertaken by the Department and/or utilities to implement the Plan. More than just a final Plan for the State, this Plan, is intended to serve as a beginning of the next stage of the planning process. The Department intends to work with stakeholders and the public to update the Plan itself annually (generally in January of each calendar year).

While the Department still has to establish a specific framework for involving stakeholders and the public, we have established the following objectives for stakeholder involvement.

1) Public involvement starts with a shared understanding of challenges and opportunities;
2) Public involvement should be open to all who want to participate;
3) The process include equal access to information;
4) Public participation should create equal opportunity for deliberation;
5) The product of those events include transparent decision-making;

As part of this process, the Department plans to have fairly focused stakeholder workshops, open forums, and opportunities for education and discussion with broader public participation. The topics identified will be both short and long-term in character.

ACTION PLAN (2005-2025)

The discussion below summarizes the actions and recommendations contained within the body of the preceding chapters. For a full discussion of a topic, refer to the discussion in the body of the Plan.

SHORT-TERM ACTION PLAN (2004 – 2007)

Planning

- The Department shall engage in efforts to create and ongoing stakeholder and public dialogue on both immediate issues and the longer term plans for future state energy policy;

<u>Electric Supply</u>

Renewables

- Vermont regulators should establish proceedings for adopting appropriate recommendations of the Advisory Commission on Commercial Wind Energy.
- The Departments and State agencies should support the regulatory review and next-state developments resulting from the investigation of the Advisory Commission on Commercial

Wind Energy into permitting issues. Recommendations identified Act 248 review as the appropriate vehicle for reviewing commercial wind generation projects, 10-mile radius notification, notifications requirements to municipalities and planning commissions, and a decommissioning fund for site restoration. The recommendations also include the use of an ombudsman contact for the Section 248 review process.

- Vermont should continue to encourage and promote development of net-metered renewable energy applications in appropriate locations.
- Vermont should promote the use of PV systems in those markets where they can be cost effective substitutes for line extensions or temporary installations.
- Vermont utilities should evaluate, develop, and implement well-designed and properly focused voluntary green-pricing programs.
- The DPS and State government should evaluate financial incentive mechanisms to foster renewable energy deployment.
- Electric utilities should explore potential for appropriate new renewable resource acquisitions as existing energy sources and contracts expire.
- Vermont utilities should work with merchant generators and developers of renewable energy projects to encourage and overcome artificial barriers to the development of cost-effective viable renewable energy projects.
- State regulators and utilities should monitor renewable technology improvements and assess cost-effectiveness and applicability for Vermont. Their federal legislative delegation should be encouraged to seek additional funds for advanced technology to support renewable energy development in the state.
- State regulators should encourage utilities and independent power producers to investigate the feasibility of retrofitting existing wood burning generators with “fluidized bed” systems.

Other Supply Options

- Identify barriers to co-generatino and facilitate discussion amongst utilities and industrial customers.
- Facilitate discussion of local generation options for utility-scale projects, including wind and natural gas.

Energy Efficiency

- Vermont should maintain its strategy of capturing energy efficiency savings through an efficiency utility, but should regularly evaluate the effectiveness of EEU programs and make adjustments as warranted by these evaluations.
- Future Stakeholder Participation in Evaluation -- The suggestion that greater public input is needed is well taken and the Department plans to determine and implement an effective public input process for future EEU evaluation plans, evaluations, and in future planning.
- Impact Analysis -- Wherever possible, evaluation of EEU programs will include actual empirical estimates (i.e., impact analysis) of savings levels actually achieved based on billing history and/or analysis of appropriate comparable patterns of consumption.

- Rate Impacts – Establishing a credible rate impact analysis will help advance and focus debates around the EEU on core issues of program design, equity constraints in the deployment of programs, and overall cost-effectiveness.
- Vermont should develop strategies for differentiating efficiency program delivery based on considerations that differentiate one area from another based on consideration for locational marginal price and area congestion.
- Vermont utilities should encourage demand response as means to reduce demand and to decrease costs, particularly in areas where congestion may cause reliability to degrade or increase costs.
- Vermont state government should continue to play a leadership role in pursuing opportunities for energy efficiency and conservation through the Clean State Initiative and the Climate Change Action Plan.
- As Vermont utilities shift from winter to summer peaking systems, utilities should develop strategies for encouraging summer load management through appropriate strategic load management and demand management technologies. Appropriate use of customer price signals, and incentives may be appropriately targeted to foster adoption of appropriate customer strategies and technologies.

Integrated Resource Planning and Decision Tools

- Vermont regulators and utilities should review the IRP process and implementation to ensure that the current process is being used effectively by Vermont's electric utilities, and to determine whether the IRP process can be made more useful to current circumstances. Utilities and regulators should explore opportunities for streamlining the IRP process and review.
- Vermont customers may benefit if VELCO, in coordination with its members, were to develop an IRP that embraces resource parity and a balanced portfolio of market-based generation, demand side management, and transmission expansion options.
- Vermont regulators should encourage advanced decision and analytic techniques in electric utility integrated resource plans and distributed utility planning rules. As new integrated resource plans are developed and submitted, these plans should adequately account for uncertainties regarding future load growth, fossil fuel prices, wholesale electric prices, and the costs of new, cleaner generation technologies.

Improve Regulatory Clarity

- Vermont regulators must consider the perception of regulatory clarity in Vermont. Among other things, changing markets will require clarity as to:
- Appropriate levels of supply and price hedging by utilities,
    - Availability of market price adjustment clauses (through alternative regulation), and
    - The applicability of principles for determining a utility is recovery of costs.

Permitting

- Environmental permitting continues to represent an important feature of the existing regulatory environment. However, opportunities may exist for ensuring that such permitting does not cause undue harm to for delivery of least cost energy services, consistent with legislative objectives. The Department should work with permitting agencies to explore opportunities for improving the permitting of resources.

Distributed Utility Planning and Distributed Generation

- There are a number of issues associated with DU planning, including establishing appropriate back-up rates, which need to be addressed in the context of distributed generation.
- Vermont's electric utilities, utility regulators, and Agency of Natural Resources (ANR) should work collaboratively to determine model-siting guidelines for fossil-fueled distributed generation resources and biomass resources.
- Vermont should explore appropriate strategies that include the participation of local residents in addressing siting issues associated with DU resource selection and placement.
- In the case of distributed generation, questions of ownership, financing, and reimbursement may need to be addressed. Strategies for addressing such issues should be developed and applied.

Low-Income/Affordability

- Vermont regulators should investigate, cooperatively with Vermont utilities, the current utility costs associated with unaffordable bills for low-income consumers. This cost study should consider all cost impacts in order to identify the full potential benefits of a low-income electric assistance program.
- Vermont should convene a study committee composed of utility representatives, low-income advocates, and regulators to conduct a review of available models and a cost-benefit analysis of at least one model for a low-income electric energy assistance program in Vermont. The results of that study should be used to guide public policy on the establishment of such a program.

Public-Private Partnerships

- Vermont should continue to aggressively pursue public-private partnerships that are economically feasible and fit in its resource needs and plans.

Performance-Based Regulation

- Vermont utilities and regulators should begin designing and implementing alternative, performance-based regulation to encourage superior performance for consumers.

Rate Design

- Vermont utilities should evaluate new electric rate designs that encourage economic growth through more efficient pricing.

Vermont Yankee

- Vermont utilities should look to mitigate the risk associated with reliance on a unit contingent contract with Vermont Yankee for such a significant portion of the annual energy needs of the State.

- Regulators should examine the implications of a potential license extension, since an application for extension will need to be submitted to the Nuclear Regulatory Commission (NRC) within the next three years.

Portfolio Diversity and Long Term Planning

- The Department of Public Service (DPS) and electric utilities should monitor and evaluate electric generating resource portfolio diversity. We must ensure that Vermont's overall electric portfolio is sufficiently diverse, especially in light of the potential loss of major generating supplies.
- Given the uncertain outcome of Vermont's pursuit of an interest in the Connecticut River hydro facilities, the DPS and utilities should begin discussions around possible local generation options.

Cogeneration

- Utilities and the DPS should evaluate incentives and viable means to enhance deployment of co-generation systems.

Wholesale Market Design

- Vermont regulators and utilities should continue to closely monitor regional wholesale market design to ensure an effective and vibrant market for wholesale power, and participate actively in the Regional State Committee (RSC) to address resource adequacy and fuel diversity issues.
- Vermont regulators and utilities should continue to closely monitor transmission network expansion plans to help ensure that regional network upgrades, for which Vermont pays a share, reflect their goals of meeting needs through least-cost resource acquisition.

Retail Choice

- Vermont should re-examine the benefits and costs of retail choice for consideration at some point in the future, building from both positive and negative experiences within the region and nationally.
- The DPS should monitor the performance of neighboring states to evaluate the relative merits of individual plans, and features of successful design.

Utility Consolidation

- Vermont utilities should study the merits of utility consolidation or other opportunities, such as shared service arrangements, to secure potentially more efficient and lower-cost operations.

Performance Monitoring

- The DPS should evaluate progress towards reducing relative electric rates in Vermont compared with other New England states. Each year, the DPS will prepare an assessment of the relative rates of Vermont electric utilities compared with other New England states and nationwide.

MID-TERM ACTION PLAN (2007 – 2012)

Vermont Yankee

- If VY is unlikely to be shutdown prematurely in 2007 or 2008 because of a lack of new spent fuel storage, it will be important to begin planning for the expiration of the existing license in 2012.

Meeting Long-Term Resource Needs

- Vermont utilities should begin active negotiations with Hydro Québec to determine their interest in replacing all or part of the existing Vermont Joint-Owner's (VJO) contract power.

Retail Choice

- Vermont should consider re-examining the suitability of retail choice. The experience of neighboring states can guide our path and inform sound design.

Renewables

- State regulators and the utilities should vigorously evaluate the results of voluntary utility green pricing programs and propose program changes to increase their acceptance and potential for additional renewable electric supplies
- State regulators and utilities should continue to monitor renewable electric generation technology improvements and identify opportunities and remove artificial barriers to deployment of proven technologies such as wood, wind, and solar both large and small scale could benefit the Vermont economy and ratepayers.
- Based on what we learn from our evaluation of voluntary programs and other utility initiatives, state regulators should evaluate the performance of Renewable Portfolio Standard (RPS) programs and other creative solutions to promoting the commercialization and use of clean, renewable technologies.

Portfolio Diversity and Planning

- Vermont regulators and utilities should monitor and evaluate electric generating resource portfolio diversity and ensure that their overall electric portfolios are sufficiently diverse, especially in light of the potential loss of major generating supplies.
- The DPS should continue to evaluate progress towards reducing relative electric rates in Vermont. State regulators should evaluate the impacts of adopted performance-based regulation schemes.

Energy Efficiency

- Vermont regulators should continue to regularly evaluate the effectiveness of EEU programs.

LONG-TERM ACTION PLAN (2012 – 2024)

- State regulators and utilities should ensure that there are specific plans for replacement of the Hydro Québec/Vermont Joint Owners contract in place by January 2015.
- State regulators should continue to evaluate progress towards reducing electric rates in Vermont relative to the rest of New England.
- The DPS and utilities should continue to monitor technology improvements, especially those promoting the development of a sustainable, hydrogen-based economy.
- Efficiency and demand response programs should be continuously evaluated for improvement and expansion.

Appendix A: Integrated Resource Planning Guidelines

INTRODUCTION

Under 30 V.S.A. '218c[1] each regulated electric or gas company is required to prepare and implement a least cost integrated plan for provision of energy services to its Vermont customers. The *Vermont Electric Plan* and PSB Orders, beginning with Docket 5270, define requirements that a utility's complete IRP should meet in order to pass the Department's review and comply with the Board's approval requirements.[2] The content and organization for a utility's plan should follow the guidelines presented in this chapter.

The objective of the integrated resource planning process is to assure that utility customers are provided with safe and reliable service while reasonably balancing the costs and benefits of providing this service. The cost factors to be considered are both direct dollar costs and those indirect costs that are hard to quantify in dollar terms, such as environmental and societal effects, which are referred to as externalities.

These guidelines establish a consistent format for the development of integrated resource plans (IRPs), also known as a least cost integrated plans (LCIPs). The LCIP process and the implementation of each Vermont utility's approved plan are intended to meet the public's need for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and

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[1] 30 V.S.A. § 218c. Least cost integrated planning

(a)(1) A "least cost integrated plan" for a regulated electric or gas utility is a plan for meeting the public's need for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs.

(2) "Comprehensive energy efficiency programs" shall mean a coordinated set of investments or program expenditures made by a regulated electric or gas utility or other entity as approved by the board pursuant to subsection 209(d) of this title to meet the public's need for energy services through efficiency, conservation or load management in all customer classes and areas of opportunity which is designed to acquire the full amount of cost effective savings from such investments or programs.

(b) Each regulated electric or gas company shall prepare and implement a least cost integrated plan for the provision of energy services to its Vermont customers. Proposed plans shall be submitted to the department of public service and the public service board. The board, after notice and opportunity for hearing, may approve a company's least cost integrated plan if it determines that the company's plan complies with the requirements of subdivision (a)(1) of this section.

[2]. The terms least cost integrated plan (LCIP) and integrated resource plan (IRP) are used synonymously and interchangeably. Natural gas utilities (of which there is only one in Vermont at this time) are also subject to '218c, but not to '202 which establishes this Plan.

economic costs, through a strategy combining investments and expenditures on energy supply, transmission and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs. (30 V.S.A. '218c)

This process is also intended to facilitate information exchange among utilities, regulatory agencies, and the public and culminate in the filing of utility plans that satisfy the standards for Department review and Board approval so that prompt and full implementation can follow.

FILING AN IRP

A complete revision of the entire IRP should be undertaken at least every 3 years. For all filings, applicable background reports, analyses, and supporting materials should be referenced and held for future public review.

DPS Review. The utility should file an IRP that is complete and in accordance with these guidelines and Board Orders. DPS will normally then perform a preliminary review to determine whether the filing is complete and reviewable. If DPS determines that the IRP is not complete and appropriate for detailed review, it will inform the utility and request that the IRP filing be completed. Upon receiving a complete and reviewable IRP, the Department will perform a detailed review and will then submit to the Board its conclusions as to whether the IRP is consistent with the *Vermont Electric Plan*, Board Orders, and state statutes. If requested by a utility, DPS will confer over an IRP filing as it is being prepared in an effort to enhance its quality and avoid disputes and remedial work.

PSB Review and Approval

If a utility requests that the Public Service Board approve their IRP, the review typically includes a hearing, and based on the evidence of record, a determination as to whether a utility's IRP is consistent with 30 V.S.A. 218c, Docket 5270, and other relevant PSB Orders. The Board may approve the IRP, approve it in part and reject it in part (both with and without conditions), or fully reject it. Solid proposals will enable the approval process to be swift. All parties should seek to avoid lengthy approval processes for IRPs.

DISTRIBUTION OF THE IRP

Utilities should file copies of the IRP and any revisions or updates with the Board and the Department; three copies with DPS and such filing with the Board as it may require. Copies of the IRP should be made available for inspection by the utility and provided upon request; at a price not to exceed publication and mailing costs, to parties that intervene in the IRP proceeding and interested citizens of Vermont.

REQUIRED DOCUMENTATION FOR APPROVAL

To be considered for approval an IRP should contain the following elements

- Executive summary suitable for distribution to the public, with an overview of the major components of the IRP and information on how to obtain a complete copy.

- IRP document that includes the components described below, including the utility's energy and peak forecast, the resource assessment, supply resources, DSM resources, T&D assessment, an integration section, and an implementation plan.
- Technical appendices should contain information that will enable the Department, the Board, and intervening parties to understand, with sufficient detail and clarity to verify and reproduce the results, how the plan was developed and to verify the accuracy and consistency of information used and assumptions made in developing the plan. Technical appendices should also include documentation and explanations of all data, assumptions, models, and outputs used in development of the plan; outputs from such models, results of uncertainty analysis, and references to all significant sources of information used in the development of the IRP.

ENERGY AND PEAK FORECASTS

Base Case forecast

A complete IRP should include a base case long-term load forecast to ensure that adequate resources are available to meet customer needs. Energy and peak load forecasts are needed. The energy forecast should be broken down to show individual customer classes, own use, and losses, with further disaggregation, as possible, to the end-use level. Customer counts should be developed separately from the demand characteristics of customers within each customer class. Energy peak load forecasts should be given for both winter and summer power periods.

A characterization of the end-use profile of a utility's load should be developed and analyzed by customer class for major categories of end use.

Any economic and structural trends expected to significantly affect a utility's future demand should be incorporated in the base-case forecast. Among those likely to significantly affect future demands for electricity are prices of electricity and competing fuels, income, demographic changes, economic output, and government actions, such as appliance efficiency standards.

Utilities should also develop suitable inputs for production simulation from the base-case load forecast. Expected energy and capacity requirements for each power year forecasted and appropriate load curve projections, or the equivalent, are needed for production simulation or capacity expansion models.

A clear and complete description of the forecast methodology and assumptions should be provided, along with a discussion of the methods and sources used to derive assumptions.

Reliance on trend variables for long term forecasts as a substitute for explicit treatment of key forecast drivers (model structure) is generally discouraged. Where heavy reliance on such variables exists, it should be carefully supported. If separate models are developed and used for short-term and long-term forecasting, the utility is responsible for providing adequate support for both, along with a clear explanation of methods used by the utility in combining the forecasts.

Post DSM Forecast

This forecast should integrate DSM program activities into the load projections and account for major determinants of future load including relevant government policies, for example appliance efficiency standards that are expected to significantly influence load growth over the long term. In order to accomplish this, it is recommended that energy sales for residential and commercial customers classes be made on the basis of end use analysis.

Information Requirements

Recent historical data (minimum of ten years) and forecasts for the 20-year planning period, starting with the year in which the plan under consideration is being filed, should include the following information:

- Customer counts, by class;
- Total annual sales of electricity by customer class and season;
- Peak load by season;
- Annual sales and coincident system peak contribution for each major customer class;
- Annual sales to other utilities;
- System energy and peak losses;
- Description of the model including the relevant variables, coefficients, and the form of the final model;
- Summary statistics and diagnostics performed on the final model;
- Characterization of the process used in the development of the final model including all variables considered and rejected;
- Description, including sources, for assumptions including end use detail where applicable;
- All historic values used in estimating model coefficients;
- Description of the purpose for including qualitative (dummy) variables, composite variables, and trend variables used in the model;
- Independent drivers for the forecast, fully documenting the basis for projecting them; and
- Numerical data available in electronic formats usable by the Department and Board.

Modeling for Uncertainty

IRP analysis should characterize the principal sources of uncertainty and the associated risks to utilities and their customers. It should go beyond uncertainties in load to consider other factors that may present risks to the utility and its customers such as fuel prices, loss of a major source of supply, and other key forecast drivers and assumptions behind the base case forecast and resource mix. Where analysis reveals unacceptable levels of risk to the utility and its customers with its present portfolio, the utility should characterize avenues for addressing such concerns. A more detailed discussion of the recommended methodology is provided in Chapter 8.

Updating the Forecast

Forecasts should be updated on a regular basis and as significant changes in the environment require (e.g., economic conditions or government policies that may significantly affect future demand such as standards or taxes). Utilities should also redo forecasts that demonstrate poor performance.

Graphic Presentation and Electronic Formats

The utility should include graphical presentation of the data wherever graphics make the data more understandable to the public. Numerical data should also be available in electronic format for the

Department and the Board.

ASSESSMENT OF RESOURCES - GENERAL

The inventory of committed or available resources to be analyzed for cost-effectiveness in preparing an IRP includes supply side resources, transmission and distribution efficiency improvements, resources gained through DSM (all of which are discussed in detail below), and resources obtained through rate design.

A complete IRP includes costs, energy and capacity contributions or savings, and timing requirements for present commitments as well as for a reasonably comprehensive group of prospective options.

For current and planned supply projects, source characteristics, capacity and energy provisions, important terms, and costs should be presented in detail. Fuel prices should be forecast, and the cost and operating characteristics of future generating units should be determined.

All projects, whether intended to increase supply or modify demand, may affect system stability, reliability, and flexibility. Each may have inherent uncertainties that complicate strategic planning but which should be weighed. Also, projects may have impacts on the environment, on public health and safety, and on the economy. The advantages and drawbacks, the longevity, and the scale of these impacts should be assessed for each option (in a qualitative manner if necessary).

Other considerations to be addressed include capability responsibility, pool operations, spinning reserve, legal obligations, instate control of resources, use of renewable resources, and contributions to other public concerns. Utilities should quantify project impacts and uncertainties whenever possible and provide a careful assessment of those considerations that cannot be quantified. Identifiable costs borne by the utility, such as the costs of environmental controls, are to be included in project costs. Additional costs particular to the nature and location of a project and borne by society should also be identified and quantified to the extent possible.

SUPPLY SIDE RESOURCES

Current Inventory

Utilities should investigate supply side resources that may reasonably be available to it within the 20-year planning period. This investigation should include a wide range of fuel types (including renewable fuels), technologies, and ownership of resources. Types of resources, among others, that a utility shall investigate include:

- Existing and committed base case generating capacity and firm power transactions currently under contract;
- Potential changes to existing resources, including, but not limited to, re-powering, fuel switching, and life extension of power plants, loss reduction in transmission and distribution systems, regional dispatch of power plants, and improvements in efficiencies including, among other areas, in power plant thermal efficiency and heat rates;
- Renewable resources;
- Utility construction and jointly developed projects;

- Purchases from qualifying facilities, including purchases obtainable through bid solicitation programs, if any, approved by the Board;
- Purchases from independent power producers, including purchases obtainable through bid solicitation programs, if any, approved by the Board;
- Purchases from other utilities;
- Customer owned generating capacity that is not a qualifying facility or independent power facility; and
- Resources developed through pooling, wheeling, coordination arrangements, or through other mechanisms.

The utility should develop and include the following information with respect to supply side resources that it investigates:

- Name and location;
- Rated capacity and net capability;
- Equivalent availability factors and capacity factors;
- Applicable heat rates;
- Transmission path and costs;
- Specification and description of fuel types, including, with respect to resources using coal, description of the quality of the coal(s) used;
- Expected remaining useful life;
- Historical fuel prices for the past five years plus projected fuel prices over the planning horizon or life, including high, base and low estimates and justification thereof. The fuel forecast should be consistent with the high, base, and low growth forecasts used in the load forecast;
- Historical, fixed, and variable costs for producing energy for the past five years, and projected fixed and variable costs of producing energy over the planning horizon; and
- Emission rates (expressed in pounds emitted per Kwh generated) of the following substances:
    - Oxides of sulphur;
    - Oxides of nitrogen;
    - Nitrous oxide;
    - Carbon dioxide;
    - Carbon monoxide;
    - Volatile organic hydrocarbons;
    - Particulates (PM10 or TSP if PM10 is not available);

- Methane;
- Chlorofluorocarbons and other ozone depleting substances; and
- Air toxics, as defined in Title III of the Clean Air Act.

- Description of any significant future changes to emissions of the above substances that are presently known;
- Comprehensive analysis of proposed compliance with Title IV of the Clean Air Act Amendments of 1990; and a
- Description of impacts on land use (including solid waste disposal) and water resources.

SUPPLY OPTIONS INVENTORY. With respect to potential generating facilities that are identified as options for meeting load during the planning period, the following additional information should be provided:

EXISTING UTILITY OWNED RESOURCES that will serve as future resources should be described, including potential costs of, and schedules for, re-powering, fuel switching, line extension, and improvement in efficiencies including, among other areas, heat rates and thermal efficiency.

NEW SUPPLY RESOURCES that a utility has already identified should be discussed as specified above for resources in the current inventory, plus construction cost, construction schedule, and expected in-service date.

OTHER NEW SUPPLY RESOURCES, including generic resources, should also be described in terms of the potential for development of these options by technology and fuel type, addressing the likely costs of construction and production (including a range of projected fuel prices), environmental and other impacts, and availability of these options during the 20-year planning period.

NEW NON-UTILITY OWNED GENERATING FACILITIES should be identified, along with options likely to be available during the planning period. The utility should also describe the potential for such facilities by technology and fuel type, the likely amounts of capacity and energy available from such facilities at various assumed prices, ownership, the environmental impacts of such facilities, and the availability of such capacity and energy during the 20-year planning period.

IMPROVEMENTS IN THE EFFICIENCY OF SUPPLY OF ELECTRICITY should be identified and discussed in terms of potential costs and benefits, and schedules for such improvement in the 20-year planning period.

POWER POOLING AND INTER-UTILITY COORDINATION opportunities should be identified, including a description of the resource potential and costs of additional power pooling and other forms of coordination with other utilities.

CURTAILABLE AND INTERRUPTIBLE SERVICE OFFERNGS TO IMPROVE SYSTEM CAPACITY UTILIZATION. The utility should include an analysis of the potential for curtailable and interruptible service offerings to its customers in order to improve system capacity utilization.

OFF SYSTEM SALES CONTRACTS WHEN THE UTILITY HAS EXCESS CAPACITY. When a utility has excess capacity, analysis should be provided in the IRP concerning how it intends to increase efficiency through management of off system sales.

TRANSMISSION AND DISTRIBUTION EFFICIENCY IMPROVEMENT

A utility should plan and conduct a comprehensive study evaluating options for improving transmission and distribution system efficiency. Based on the findings of that study, it should then implement a program to bring its T&D system to the level of electrical efficiency that is optimal on a present value of life cycle societal cost basis within a reasonable period of time. These studies and action plans should be reviewed and updated at reasonable intervals. Finally, each utility should implement a program, as part of its IRP, to maintain T&D efficiency improvements on an ongoing basis.

T&D System Evaluation

Each utility should evaluate individual T&D circuits to identify the optimum economic and engineering configuration for each circuit. Reliability and safety criteria should be reflected as applicable. The filed IRP should contain a written plan describing how and when the utility will carry out these evaluations

Decisions regarding some facilities may affect more than one utility. In such instances, utilities should work together so that their evaluations reflect not only their individual interests, but also the interests of ratepayers generally.

The standard for establishing optimum T&D system configurations and for selecting transmission and distribution equipment is the net present value of life cycle societal cost. This requires consideration of a project's capital costs and life cycle operating costs, as well as benefits resulting from the construction of enhanced system configurations and the installation of energy efficient T&D components. These benefits include avoided operation and maintenance costs, and avoided energy and capacity costs. Avoided energy costs include the direct costs for energy, the costs for energy consumed as line losses, T&D delivery costs, and environmental externalities. Avoided capacity costs include fixed costs and capacity charges for power including on peak line losses, fixed costs and capacity charges for T&D, the cost of Capability Responsibility reserve obligations, the deferral of T&D investments, and environmental externalities.

- Evaluations should identify and compare all technically feasible investments to improve system efficiency. At a minimum, evaluations should assess the economics and technical feasibility of the following measures:
- Strategic placement and control of reactive power devices;
- Distribution circuit reconfiguration;
- Installation of distribution automation to control reactive power, feeder configuration, phase balancing, and peak loads;
- Re-conducting lines to larger-sized conductors;
- Replacement of conventional silicon steel core transformers with high efficiency silicon steel transformers or amorphous metal core transformers;
- Conservation voltage regulation;
- Increasing distribution system voltage levels;
- Implementation of a distribution transformer load management (DTLM) program (See Equipment Selection and Utilization Standards below);

T&D Equipment Selection and Utilization Standards

Utilities should develop and adopt any necessary procedures to meet the following standards:

- All transformer and capacitor selection and purchase decisions fully reflect the societal value of projected capacity and energy losses over the equipment lifetime with due regard for expected loadings and duty cycles;
- Inventory of transformers in use and on hand is to be managed to match transformer loss characteristics with customer load factors; and
- An ongoing system to monitor and adjust transformer loading for optimal economic benefit is in place.

Regarding the second standard listed above, this program should first establish a link between the utility customer or meter accounts and the distribution transformer that provide services to these customers. This is to enable utilities to monitor monthly energy demand on each transformer, and to provide data that will enable utilities to estimate peak transformer demand. (Distribution transformer load management software is presently available for this purpose.) This information will permit utilities to manage transformer loading more efficiently and postpone transformer replacement or pin-point over-loaded or inefficient units in service. These efforts will also be useful in conjunction with voltage conversion or other programs that involve significant investment. For transformer replacement, this program has the potential to provide significant benefits permitting utilities to match transformer capacity and loss characteristics more closely to customer load characteristics.

IMPLEMENTATION OF T&D EFFICIENCY IMPROVEMENTS. As individual circuit evaluations are completed, utilities should schedule the implementation of all cost-effective measures within a reasonable period of time. A utility's IRP should note any progress-to-date in the evaluation of circuits, the development of implementation plans for circuits in which evaluations have been completed, and the completion of efficiency measure installations.

MAINTENANCE OF T&D SYSTEM EFFICIENCY. Transmission and distribution systems are dynamic in nature, i.e., their configurations and capacities change over time to meet the changing needs of customers. Consequently, the implementation of a set of efficiency measures on a given circuit should not mark the end of the attention given to that circuit. Rather, T&D system optimization should be pursued as an ongoing effort. Therefore, utilities should, as part of their planning efforts, set out a program for maintaining optimal T&D efficiency. This program and progress in it should be reported thoroughly in the utility's IRP and describe, through operating procedures, design criteria, equipment replacement standards, etc., the manner in which optimal T&D efficiency will be maintained. All subsequent cost-effectiveness analyses performed under this program should maintain the standard of present value of life cycle societal costs.

OTHER T&D REQUIREMENTS

In addition to the requirements outlined above, utilities should comply with the following T&D related requirements. These requirements address several areas important to T&D least cost planning and system reliability.

Bulk Transmission

VELCO, as the responsible planner for Vermont's bulk transmission system on behalf of Vermont ratepayers and utilities, should give special consideration not only to the efficiency of its own facilities, but also to the impact its actions may have on the efficiency of sub-transmission and distribution. Where appropriate, VELCO should support and cooperate with others in undertaking regional T&D optimization studies. The societal test coupled with suitable probabilistic reliability analysis and attention to strategic planning issues should form the basis for planning and technical evaluation. Where additional transmission capacity is required, the preferred method for increasing transmission capacity should be through the upgrading of existing facilities within existing transmission corridors unless it can be demonstrated that such a measure would have a substantial adverse impact on the electric system or societal costs.

Sub-transmission

Sub-transmission planning should take into account broader interests than those of individual utilities. Where appropriate, integrated regional reliability improvements and transmission system optimization should form the basis for the basic planning and technical evaluation criteria. Utilities should cooperate as needed to assure efficient operation and installation of sub-transmission plant while also assuring an acceptable level of reliability, justified by suitable probabilistic analysis. If necessary, joint utility or utility-regulatory processes should be established to coordinate this activity.

Distribution

Duplicate electric facilities are generally not in the public interest. The Board is authorized by statute (30 V.S.A. '250) to designate exclusive service territories for electric utilities in order to reduce or eliminate the existence of duplicate electric facilities. Where duplicate electric facilities exist, the companies responsible should seek to eliminate the duplication to the extent possible.

In the process of building, rebuilding or relocating lines to roadside, electric utilities should coordinate with the appropriate telephone and cable TV companies during the planning and construction phases to ensure that, wherever possible, no permanent duplicate facilities are installed along the same road and that the transfer of existing facilities to new or rebuilt poles is done in an expeditious manner.

While there can be significant benefits from roadside relocation of distribution lines, this activity can have a significant adverse impact on Vermont's scenic landscape. Therefore, companies proposing extensive roadside relocation programs should work with all interested stakeholders (ANR, Department of Forests, Parks and Recreation, DPS, and local government) to address aesthetic concerns, including techniques or approaches that mitigate the impact on aesthetics. Where the relocation would have only a minimal impact on visual resources, little or no mitigation may be required. However, for projects in areas with high-value visual resources more extensive mitigation procedures should be considered including:

1. Relocation to the less sensitive side of the road;
2. Use of alternative construction techniques such as spacer cable, armless construction, and relocation underground;
3. Development of a project specific vegetative management plan; and
4. Alternative routing.

These discussions should also consider other important factors such as cost, reliability, and worker and public safety.

PCB Requirements

Utilities need to incorporate in their long-range plans the cost of identifying and cleaning or replacing PCB equipment as mandated by Federal law. Those requirements should be viewed as an opportunity to make concurrent system efficiency improvements as part of a utility's IRP.

Vegetative Management Plan

In their IRPs, all utilities should describe their current vegetative management plan and, if they have not already done so, they should evaluate the merits of implementing a systematic vegetative management plan. Some of the information required in this section may be common to several of the smaller utilities, providing a potential opportunity for these utilities to share in the cost of collecting the information for their respective reports. At least one utility, Washington Electric Cooperative, has worked with the Department of Forests, Parks and Recreation on improving the utility's line clearing standards, training for utility clearing crews, updating its vegetative management plan, and cooperating on some public information and educational literature. This effort has enabled the utility to access expert arborists who can assist utilities in preparing vegetative management plans and improving tree-trimming practices. The public information and education effort is certainly an area in which materials developed by one utility could be shared by other utilities, thus reducing costs. It is important for utilities to make their customers aware of the dangers of trimming near utility lines and the importance of planting low-growing species beneath power lines. Each utility should submit its own report however, because each utility is responsible for ensuring that the tree-trimming program in its service territory is undertaken in a least cost manner.

In describing its current plan each utility shall indicate the total miles of T&D lines in their service territory, the number of miles of line that require tree-trimming, the amount of money budgeted and the amount actually spent on tree-trimming in each of the past three years, and the number of miles of line that the utility has trimmed per year in each of preceding three years. In addition, the utility shall provide a detailed explanation of why their current tree-trimming program represents the least cost program including details on the type and the relative composition of tree species present in their service territories, the annual growth rates of these species, the amount of money projected for tree-trimming for each of the next three years and the length of their tree-trimming cycle. As a means to evaluate the effectiveness of the tree-trimming program, utilities should monitor the number of tree related outages as compared to the total number of outages and provide this information in their IRPs.

Electricity Pricing

IRPs should explain whether current rate designs for each major customer class are consistent with other components of the IRP, and explain whether possible future changes in rate design will facilitate IRP goals. Load control programs should be compared for cost-effectiveness with alternative resources.

ENVIRONMENTAL IMPACT - The IRP shall demonstrate an understanding, and ideally quantify or demonstrate due consideration, any significant environmental attributes of the resource portfolio, current or planned.

INTEGRATION

In developing its portfolio of least cost resources for meeting its long term energy needs, the utility shall treat all demand and supply side resources consistently and equitable, in accordance with the follow principles:

- Using supply resources, T&D improvements, and demand-side resources that have been assessed, a consistent plan that meets the need for energy and capacity should be developed.

- This plan should minimize total societal costs, showing how externalities have been considered and including all financial, regulatory, and other significant assumptions.
- Utilities should, to the extent feasible, report the expected results of their IRP in the following areas:
  - Expected capital and operating costs of the resource plan and its effect on utility revenue requirements;
  - Impact on customer bills and rates;
  - Impact on the environment, including environmental externalities;
  - Effects on fuel and technology diversity and other factors affecting the plan's ability to respond to unforeseen changes;
  - Reliability of the system;
  - Impact on the utility's financial condition;
  - Impact on the state and local economies, to the extent feasible;
  - Use of renewable resources; and

Risk and Uncertainty Analysis

Analyses should be conducted to examine the risks and uncertainties associated with meeting the energy service needs in each forecast, including, but not limited to:

- Fuel prices for electricity production and for customer end uses;
- Variation in economic factors;
- In service dates of supply and demand resources;
- Unit availability;
- Market penetration rates for, and the cost-effectiveness of, demand-side programs;
- Inflation in plant construction costs and the cost of capital;
- Use of risk-adjusted discount rates;
- Possible federal or state legislation or regulation;
- New technological developments; and
- Unit decommissioning or dismantlement costs.

Identification of Least Cost Portfolio

Utilities should evaluate a variety of portfolio strategies, noting the uncertainty and sensitivity of each. Strategies that deliver the lowest cost under optimal conditions, but are highly sensitive to the operating environment, may not be the most appropriate choice. Strategies that achieve a relatively low cost under a variety of contingencies may be preferable.

Utilities should explicitly account for the critical interactions among potential supply options. One way to handle this is to use a multi-period optimization procedure that estimates minimum discounted societal cost. This method takes interactions among measures into account directly, but is technically quite challenging. Scenario analysis is another tool that can be used to identify the lowest cost strategy under a variety of contingencies.

The critical requirement in developing a least cost portfolio of resources is to maintain an unbiased evaluation of options to increase supply and modify demand and to fairly balance costs, risks, and societal impacts. Given the uncertainties inherent in this process, there may be a variety of projects available with identifiable costs and benefits that do not differ widely.

The integration section of a complete IRP includes a thorough discussion of the following:

1. Identification of an optimal portfolio of supply resources, bulk transmission, T&D, and rate design projects, with a summary of the expected annual energy and capacity costs or savings contribution of each selected option over the planning horizon. Significant concerns of managing the optimal portfolio that relate to financing, project timing, line loss and reserve requirements, and organizational factors should be identified along with any critical externalities that influenced inclusion of the option.
2. Discussion of the methodology and assumptions used to derive the optimum portfolio, with discussion of the sensitivity of results to important assumptions.
3. Discussion of reasonably competitive projects not included in the optimum portfolio, including reasons for exclusion, and whether or not projects will be available for consideration if the strategic environment changes.
4. Discussion of contingency plans associated with the higher risk components of the selected portfolio, including events that would alter the portfolio and trigger a utility's decision to either adopt or terminate a measure.

Preferred Plan

A complete IRP develops a preferred least-cost plan that fully explains, justifies, and documents the manner in which it was developed, including an explanation of how it ensured internal consistency in avoided costs and retail electricity prices. If the utility's preferred plan differs from the plan that minimizes total societal costs in meeting electric energy service needs, the utility will have to justify its choice.

Implementation or Action Plan

A complete IRP includes effective strategies for implementing the least-cost integrated portfolio identified in the preferred plan. For each near term program project scheduled to begin implementation within three years, utilities should develop a work plan that includes intermediate targets and milestones that can be monitored and evaluated, identification of utility personnel and anticipated outside vendor responsibilities, and provisions for identifying and adapting to contingencies as they arise. Provisions for research and data collection necessary to improve planning performance (saturation surveys, supply and demand marketing studies, distribution system mapping) can also be included as proposed action items.

A sound and complete implementation plan should include the following:

1. An overview of the preferred least cost portfolio, briefly discussing how it will be administered and updated.
2. For each near-term program project identified in the preferred plan and scheduled for implementation within three years, provide the following:

- General procedures for implementing, monitoring, and evaluating the project;
- Work plan for the project, consisting of expected implementation objectives, scheduled dates for design, implementation, evaluations and other major milestones; objectives for costs and savings; and a milestone chart graphically depicting project schedules;
- Outline of anticipated responsibilities of utility personnel and proposed consultants or

vendors; and

- Identification of important contingencies that may arise as the strategic environment changes and projects evolve, including adjustment to project plans that should be made to minimize adverse impacts.

3. For any program project identified in the preferred plan and scheduled for implementation after three years, provide a list of expected decision points and dates.

ONGOING MAINTENANCE AND EVALUATION

After its IRP is approved, a utility is responsible for administering approved projects, evaluating and reporting on progress, and effectively maintaining its IRP. Projects should be carried out in accordance with deadlines specified in a utility's implementation plan.

REQUESTING A CONSISTENCY DETERMINATION AND OTHER PROCEDURES

WAIVER OR AMENDMENT OF UTILITY PLANNING REQUIREMENTS

For good cause soundly demonstrated, the Director for Regulated Utility Planning may waive or amend any requirement of this Plan. Requests for waiver or amendment of requirements should be submitted to the Director in writing well in advance of the intended deviation.

Good cause includes demonstrated economic or other utility-specific inappropriateness of a substantive requirement. A request for change of a substantive requirement should include one or more proposals for alternative and appropriate means of fulfilling the original purpose of the requirement or demonstrate why no reasonable alternative would be appropriate.

CONSISTENCY DETERMINATION

The Department under 30 V.S.A. '202(f) reviews certain proposed actions by electric utilities to determine the consistency of those actions with the current adopted version of the *Twenty Year Electric Plan*. Utilities contemplating proposals for actions subject to PSB approval under 30 V.S.A. ''108 or 248(b) should also request in writing the Director's determination under 30 V.S.A. '202(f).

Notification

Any company making such a proposal should notify the Director at least 60 days in advance of the proposed action and include, at a minimum, the following information:

1. A description of the proposed action; the nature of the arrangements being proposed; the capacity and/or energy and the terms of the arrangements being proposed; and other relevant information.
2. An explanation of the objectives the company seeks to accomplish with the proposed action, and how it relates to the company's short and long-range power supply plans, as well as to this Plan.

Regulatory Response

The Department will advise the company if additional information on the proposed action will be needed. If so, appropriate information requests will be made. The Department will issue the resulting determination as quickly as possible following the receipt of requested information. Typical information needed for projects includes:

Economic Analysis

Calculation of the societal costs and benefits of the proposed supply action and of the supply and DSM alternatives the utility has considered. The underlying data, including production simulations and DSM program data, should be included.

Sensitivity Analysis

Since the results of societal test analyses are highly sensitive to key assumptions that may be hard to predict, it is necessary to determine how varying those assumptions may alter the competitiveness of the proposed action. For this reason, the utility should conduct additional studies incorporating variations of those assumptions. All assumptions subject to changes that would have a significant impact on the analysis results should be reviewed. The variations to be studied may be developed with the Department in advance of filing.

Diversity Calculations

To help gauge the degree of dependence on the proposed project, a utility's analysis should show the percentage of its energy and capacity requirements the proposed action will provide during the project's life, based on production simulation results.

Similar calculations should be shown for the aggregate energy and capacity from the proposal plus all other entitlements of the utility that use similar technology and fuel.

The Department wishes to expedite the review and determination process in every way compatible with its responsibility to conduct a thorough review of proposed actions. For that reason, utilities are encouraged to initiate discussion of major proposed actions at an early date.

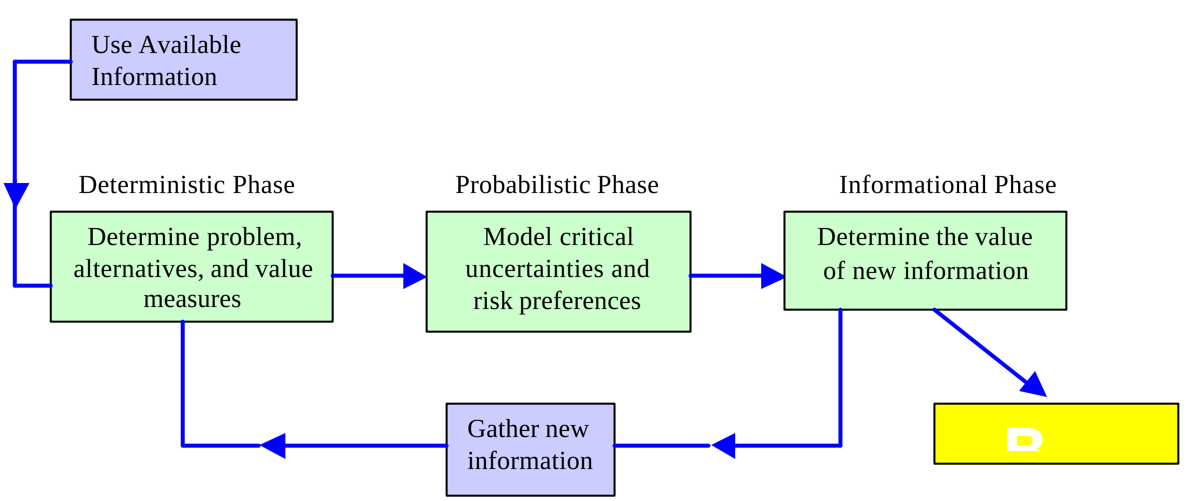
Appendix B: Decisions Analysis Framework

THE DECISION ANALYSIS FRAMEWORK

As a problem solving technique, decision analysis ("DA") was developed in the 1950s, but was actually alluded to as far back as Aristotle, in his *Necomachean Ethics*.[1] Decision analysis is a structured "process." It is a logical, step-by-step approach to working through complex, and perhaps initially unstructured or even unclear, problems. A schematic of the decision analysis process is shown in Figure B-1.

The process can be separated into three distinct phases: deterministic, probabilistic, and informational. The deterministic phase begins by structuring the problem to be solved. That is done by first defining goals and identifying a set of alternative decisions that can be made. The next step in the deterministic phase is to develop an empirical model that can value the agreed to specific goals. This allows decision makers to measure how successfully each decision alternative achieves the identified goals. The deterministic phase can be used to weed out variables that, even though subject to future uncertainty, will have little effect on the results.

Figure B-1 The Decision Analysis Process



The probabilistic phase takes the remaining variables and determines their effects on the overall values of the decision alternatives. The key step in the probabilistic phase is to represent the

[1] Decision analysis is sometimes confused with *decision trees*. While decision trees are a mathematical construct used in problem solving, they are only one aspect of decision analysis, which is a structured approach to making decisions in the face of uncertainty.

uncertainties of the important decision variables. For example, future electric market prices will affect the value associated with building a new generating plant today. In the probabilistic phase, that price uncertainty would be described analytically. In this phase, an analyst would also determine whether there were correlations among the different variables, such as between electric and natural gas prices. The probabilistic phase continues by calculating relevant probability distributions of values for each alternative, and then constructing and solving a decision "tree" to identify the preferred strategy.

The informational phase estimates the value of gathering additional information to reduce the identified uncertainties. The value of information can then be compared to the cost of obtaining new information that may be available before having to make a decision. In essence, in the informational phase, we determine the value of eliminating different uncertainties. We do this by assuming there really *is* a clairvoyant who can tell us what the future will look like.

MECHANICS OF DECISION ANALYSIS

So how is decision analysis actually performed? How are goals determined? How are values developed and used to measure those goals? What do the results of the analysis mean? How do the solutions differ from standard discounted cash flow analysis? Where is the fit between decision analysis and "real options" analysis and other valuation techniques? While comprehensive discussions of these questions would require several books worth of space, a flavor for each can be provided through an example. Consider, therefore, a hypothetical electric utility in Vermont that must choose among resource alternatives to meet its obligation to serve.

Selecting Alternative Strategies

Suppose the electric utility is projecting continued load growth that has ranged between 1.0%and 6.0%t per year. (How much growth is uncertain, and will be discussed below.) To meet this growing demand, the utility needs to acquire new sources, whether in the form of new generation or additional energy efficiency measures.

As with picking a portfolio of stocks and bonds, there are potentially thousands of alternatives. Since it is never feasible to analyze every possible option and combination, the number of decisions can be reduced using general goals such as resource diversity, risk tolerance, etc., and an initial screening of the characteristics of different alternatives. As an example, constructing a 1,000 MW (roughly the size of Vermont's peak electric load), coal-fired generating plant, can probably be rejected out of hand as a viable alternative, because it simply will not happen in Vermont owing to environmental impacts and transmission system limitations.

First, suppose that, after some initial thought, the utility develops four general options, as shown in Figure B-2. The options are to build and own a new 100 MW gas-fired combined-cycle generating plant. Because the plant would provide a lot of excess generating capacity, the surplus generation could be resold into the spot market. The second option would be to perform the site work for the plant this year, and revisit the decision to build next year, depending on market conditions and, perhaps, new alternatives. The third option would be to eliminate load growth this year using targeted demand-side management (DSM) programs. The fourth option would be to sign a contract with a wholesale supplier for 50 MW, with a price that is linked to wholesale natural gas prices.

Figure B-2 Strategy Alternatives

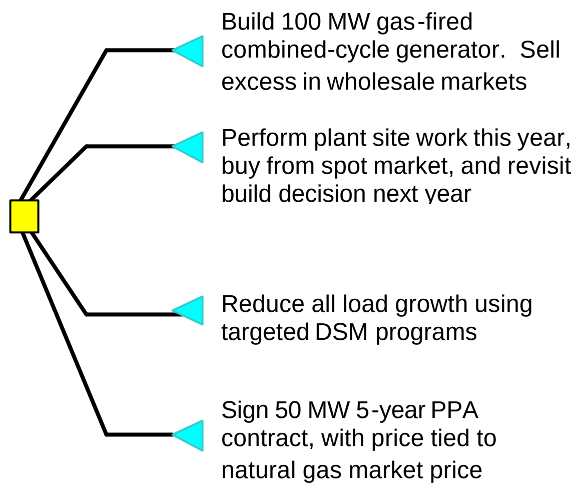
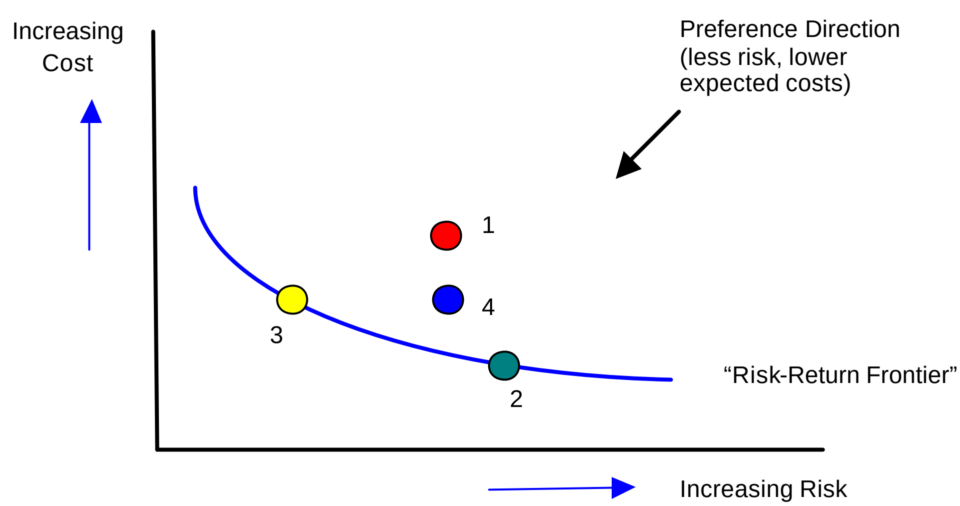


Figure B-3 Risk-Return Frontier



Each of these four possible decisions will result in an overall risk-return tradeoff for the utility, based on the utility's overall portfolio of generating resources and loads. Each resource portfolio will have associated with it a cost and risk profile, as shown in Figure B-3. For example, a strategy of relying on the spot market may have a lower average cost (as shown by the circle labeled "2") but higher risk because of the spot market's volatility. Strategy 3, however, based on additional DSM investments, may have less risk, but a higher average cost. Evaluating each strategy might also show that Strategy 1 would have the highest cost of all, and more risk than Strategy 3. If that were the case, Strategy 1 could be eliminated as a choice entirely because Strategy 3 would provide "more" of the preferred attributes (*i.e.*, lower costs and less risk) than would Strategy 1, making a choice between the two easy.

Choosing between Strategy 2 and Strategy 3 is more difficult. Both of these strategies lie along what is called the "Risk-Return Frontier." Along that frontier, the utility cannot obtain both lower costs and less risk; cost and risk must be traded-off, much as individual investors must trade off risk and return when choosing between stock market investments.

Identifying and Structuring Uncertainties:

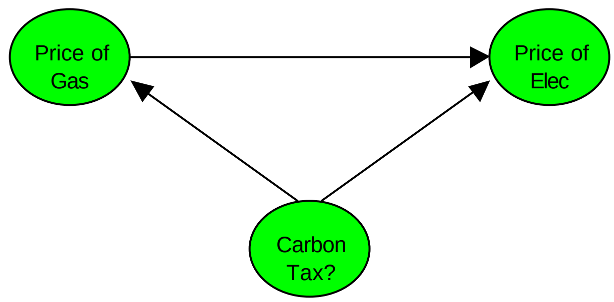
A structured decision process requires that key uncertainties be identified and their effects on decisions that must be made today evaluated. In determining the most critical uncertainties, the first step is to use economic principles to identify the most likely market-based and non-market-based uncertainties. Market-based uncertainties will include such things as the future prices of electricity and fossil fuels, construction costs, and tradable emissions permits. Non-market-based uncertainties cover a potentially broader range of factors, including the likelihood of extended nuclear plant shutdowns, prospects for future carbon regulations, changes in technology, and even such things as public relations.

Which variables will affect the costs and the benefits of the decision alternatives? Certainly the future price of spot market electricity will have an effect. So will the future price of natural gas. The cost of building the combined-cycle plant might also be uncertain, especially if the decision to build the plant is delayed until next year. The plant's operations might also be affected by future environmental regulations, such as the price of emissions allowances for oxides of nitrogen. A carbon tax could also have a significant impact, depending on when it might start and how large it was. Load growth uncertainty may also be important. The DSM strategy, for example, might not be sufficient if loads grew very rapidly, but could be the perfect choice if loads were expected to grow little.

Before the impacts of different uncertainties on the strategy alternatives can be evaluated, the uncertainties must be structured. It's fine to say that spot market prices will affect the utility's overall supply cost. But to evaluate the specific impacts and, ultimately, choose between the different resource decisions requires that we represent those uncertainties in a way that can be evaluated fairly. Specifying uncertainties also provides other advantages: 1) it allows the utility's assumptions to be evaluated, because the uncertainties are not hidden in "black-box" models; and 2) it allows us to test the impacts of changing the uncertainties to see how, or if, doing so affects the preferred strategic choice.

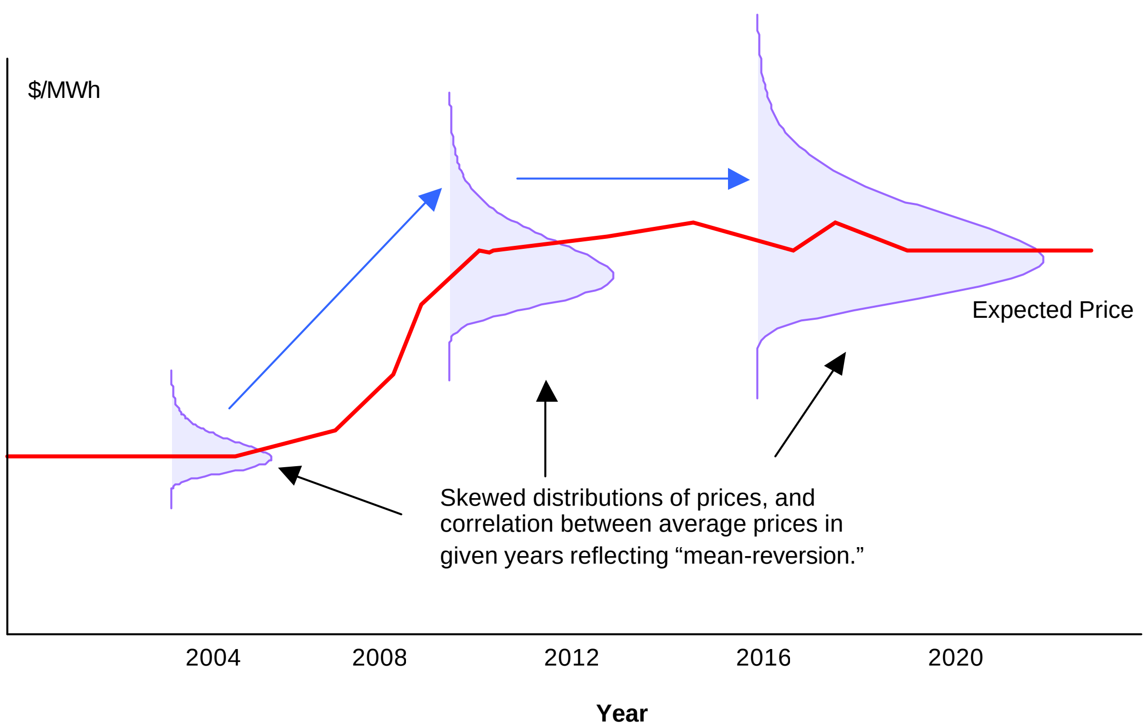
Furthermore, it is important to identify the linkages between specific uncertainties. For example, the spot market price of electricity will be influenced by natural gas prices and, if it comes to pass, regulations limiting emissions of greenhouse gases. It's often helpful to depict such relationships graphically, using what are called "influence diagrams," such as the one shown in Figure B-4.

Figure B-4 Influence Diagram



To continue the planning example, the utility might estimate that electric prices are distributed over time as shown in Figure B-5, based on underlying volatility in fuel prices, the availability of specific generating units, and the presence of transmission constraints affecting import and export opportunities. In Figure B-5, there are several things to note. First, uncertainty about future electric prices increases over time. Second, the distributions are skewed, which simply means that prices can increase more (in absolute terms) than they can decline. Third, although uncertainty increases over time, there are market fundamentals that tend to restrict overall changes.

Figure B-5 Uncertainty of Future Electric Prices

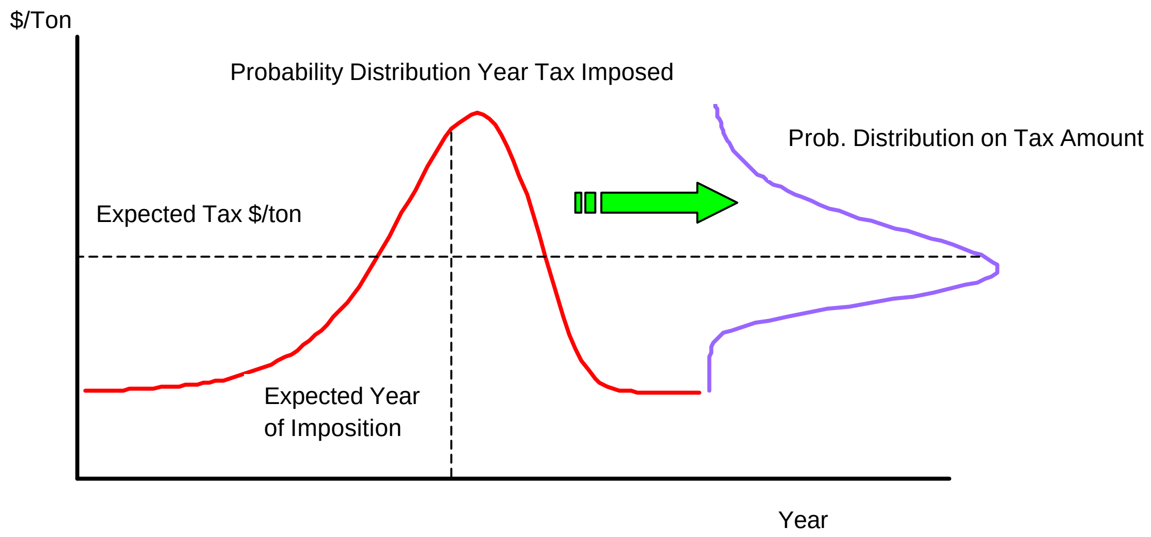


To understand this concept, consider the "doomsday" predictions made in the late 1980s of oil prices that would reach $100 per barrel, or even $200 per barrel by the year 2000. These forecasts were spectacularly wrong, not just because they were forecasts, but because there was no consideration of basic economic principles, specifically that high oil prices would encourage fuel substitution (to natural gas, greater energy efficiency, etc.) as well as stimulate additional supplies.

Market uncertainties tend to be easier to structure than non-market uncertainties because there is usually historic data that can be examined and used to develop informed judgments about the structure of future uncertainties. Non-market uncertainties, especially those that address events for which there is no previous information, are more difficult to address, but may be equally or more important.

For example, the cost-effectiveness of building the combined-cycle generating plant could be affected if the U.S instituted a broad-based carbon tax in response to the Kyoto Protocol. Here the uncertainty has three aspects: 1) *Would* a carbon tax be imposed? 2) If so, *when* might such a tax take effect? And, 3), if the tax took effect, *how large* might it be? The utility could assign a probability distribution to the imposition date, as well as a probability distribution for the amount of the tax itself. The utility might also believe that the imposition year would affect the amount of the tax, reasoning that the sooner the tax would be imposed, the smaller it would be. In that case, the probability distribution for the tax amount would be *conditional* on the year imposed, as shown in Figure B-6.

Figure B-6 Probability Distributions of Tax Year Imposition and Amount

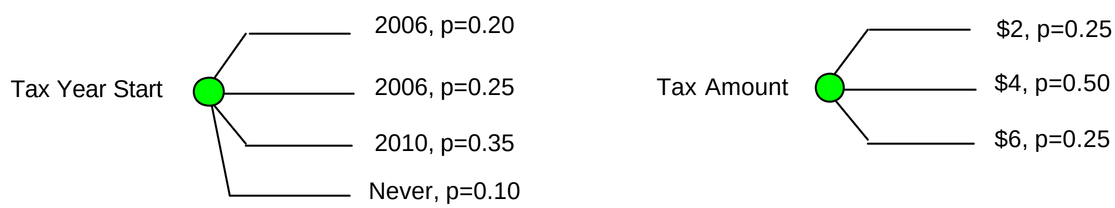


Converting Uncertainties into Discrete Events.

Except in some special circumstances, the probability distributions shown in Figures 4.5 and 4.6 need to be converted to discrete events. For example, the probability distribution for the amount of a carbon tax might have been determined to have extremes of $0 and $100 per ton. Since there are an infinite number of values in between, some way of converting that continuous distribution into several discrete events must be performed.

Fortunately, there are numerical techniques to do this that are standard in statistical and decision analysis software.[2] Usually, a probability distribution will be converted into three or four discrete events. For example, the carbon tax year and amount might be converted as shown in Figure B-7:

Figure B-7 Discrete Representation of Probability Distributions



Constructing a Decision Tree to Solve the Problem

Having identified a set of decision alternatives, determined value measures, and identified and developed discrete representations of key uncertainties, the next step is to develop a decision tree structure and determine the optimal strategy. A decision tree provides a schematic representation of a problem containing "branches" that describe the different states-of-the-world that can be realized. Figure B-8 provides an example based on the four strategies shown previously in Figure B-2.

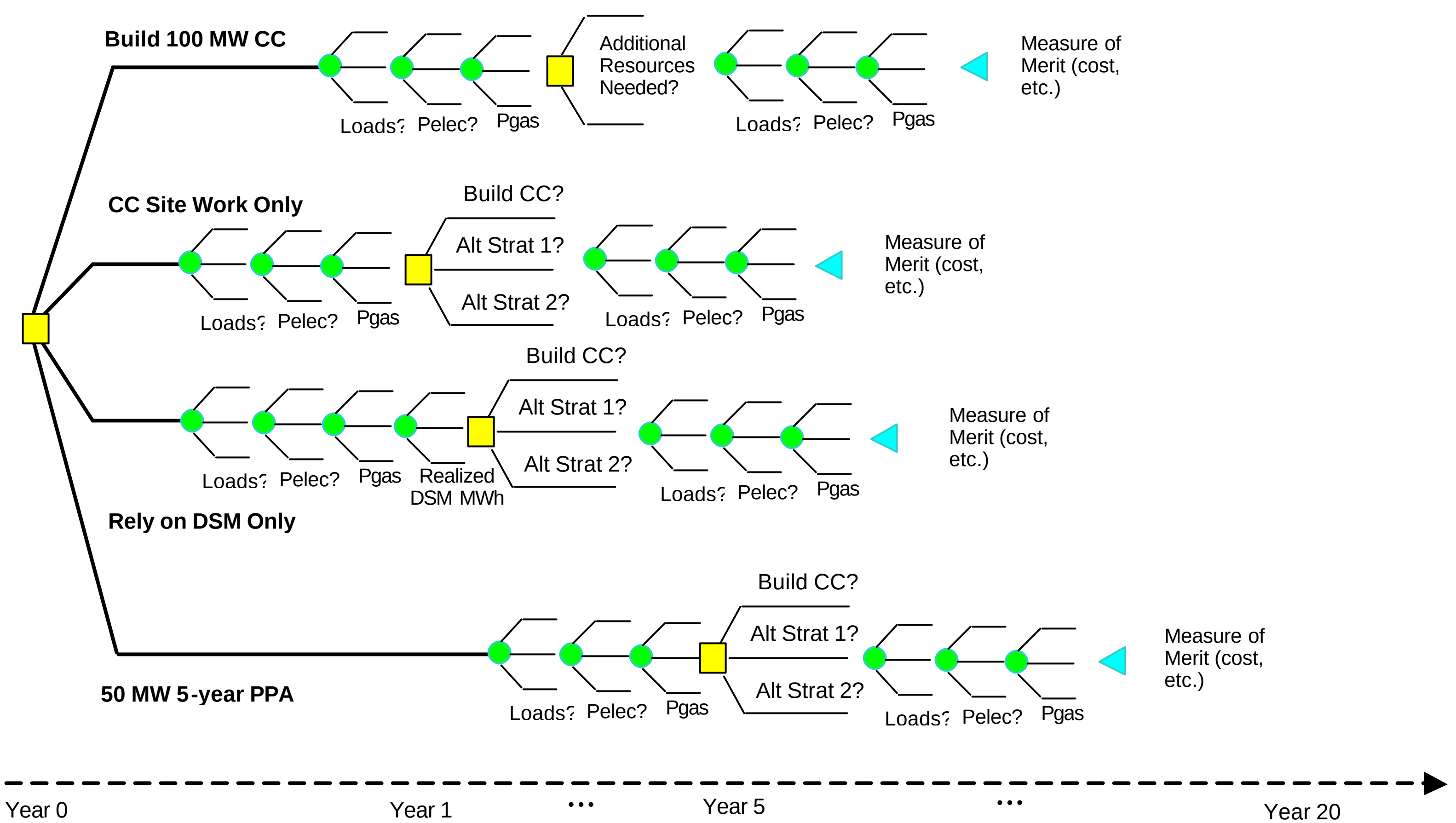
In Figure B-8, the left side of the decision "tree" begins with those four strategies. The uncertainties identified are future load growth, the future price of electricity, the future price of natural gas, and the amount of DSM savings that are achievable. There may be other important uncertainties, but these will do for the purposes of the example.

If the "Build 100 MW CC" strategy is chosen, then the utility will have plenty of generating capacity in the near term, but eventually will have to make subsequent decisions about future resources. *When* the utility will need to make such decisions will depend on realized load growth. Moreover, the utility may want to retire the CC if it is less reliable than expected or if new, less costly technologies and resource alternatives became available. (This is why a good decision making process is not a "one time only" event, but rather a continuing process of re-evaluation.)

If the utility chooses to delay construction of the 100 MW CC plant, and only performs site work for the plant this year, it is essentially buying an "option" to construct the plant in the future. Under this strategy, the utility defers the build decision by one year, relying on, for example, a short-term purchases in the wholesale market to meet customer demand. After one year, the Build 100 MW CC strategy could be re-evaluated, along with other alternatives that may be available. At first glance, it might appear that this sort of "wait-and-see" strategy would *always* be preferred to a large-scale commitment today, but that is not necessarily true. Sometimes, delaying a project can introduce unexpected new costs or foreclose on other options that may not be available later.

[2] The formal name of the technique most often used is called "gaussian quadrature."

Figure B-8 Resource Strategy Decision Tree



The value of the DSM strategy depends not only on uncertain load growth and prices, but perhaps also on the realized energy savings achieved: if load growth is rapid because of a strong economy, the available DSM savings may not be sufficient to meet that load growth, or the cost of achieving the additional DSM necessary to meet the rapid load growth too expensive. Even if the DSM is selected, the utility will need to examine other alternatives later on, including perhaps building the CC plant.

Finally, there is the 5-year PPA strategy. Again, its value depends on load growth and prices. For simplicity, the decision tree shows the utility revisiting its resource decisions at the end of five years.

The rightmost part of the decision tree shows the "Measures of merit." These are the factors that will be evaluated for each alternative strategy. For example, the measure of merit might be the overall cost of the strategy, a weighted combination of monetary cost and environmental footprint, or could include the variability of costs for a given strategy. In general, the measure of merit will show a probability distribution of outcomes, based on the uncertainties included. For example, the probability distributions of the Build 100 MW CC today and 5-year PPA strategies might have probability distributions of overall costs as shown in Figure B-9:

Figure B-9 Probability Distributions of Cost

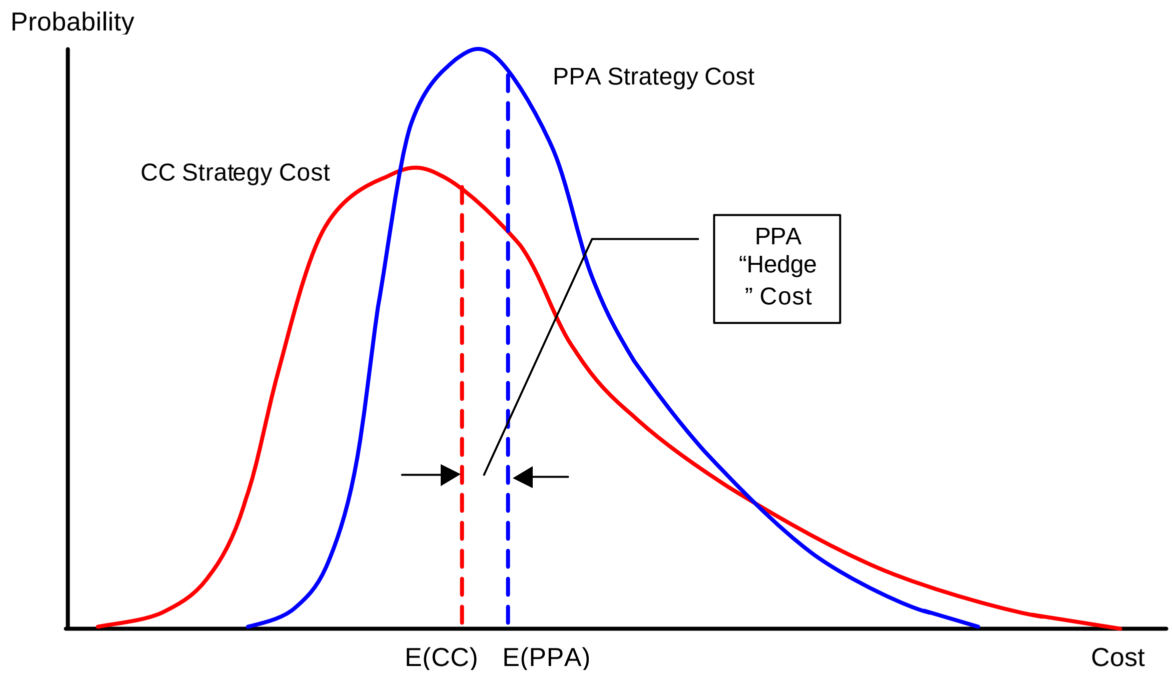


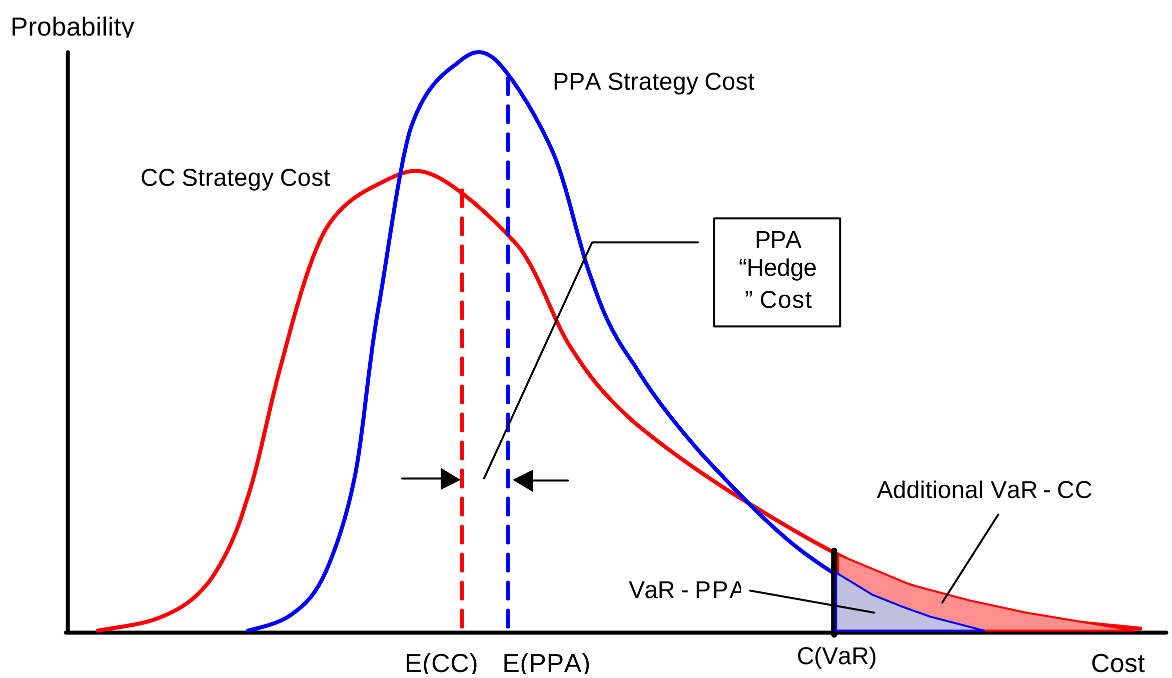
Figure B-9 show that the expected present value cost of the PPA strategy, E(PPA), is greater than the expected present value cost of the combined cycle strategy, E(CC). However, the probability distribution of the PPA strategy is "narrower," implying that is costs are less "volatile" than the CC strategy. Thus, the PPA strategy can be thought of as a "hedged" strategy. What is the cost of the hedge? It is the difference in the expected costs, as shown in the figure.

Ultimately, whether the cost of the hedge is "worth" the reduction in risk boils down to judgment: just as there is no uniquely "correct" amount of life insurance one might purchase, there is no uniquely correct hedge.[3]

Measuring Value-at-Risk

Another useful concept when addressing the volatility of any resource strategy is called "value-at-risk" or "VaR." VaR is simply a measure of the likelihood that an outcome will be beyond a given threshold value. Power traders often use VaR, for example, to determine the riskiness of their short-term power supply deals over the next day, week, or even year. The same concept can be applied to long-term resource planning analysis. Figure B10, for example, reproduces Figure B-9, but adds a given cost threshold.

Figure B-10 Value-at-Risk



The striped area labeled VaR-PPA represents the probability-weighted value of an outcome beyond the cost threshold C(VaR). The cross-hatched area labeled "Additional VaR –CC" shows the greater likelihood that the CC strategy will result in costs beyond the established threshold. The choice of the actual threshold will depend on the importance placed on volatility.

Additional "Robustness" Checks

One common concern about probabilistic analysis is the uncertainties themselves. How do we know what the uncertainties really are, and what if the structure of those uncertainties is different than what we assumed? This is a legitimate concern, although to not address uncertainty entirely because of it is to "throw the baby out with the bath water." That would solve the problem by ignoring it, which is

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[3] There are some advanced mathematical techniques that can determine whether either of the strategies shown in Figure 9 are "dominant."

rarely a good solution.

In any decision analysis exercise, it can also be useful to subject the uncertainties themselves to sensitivity analysis. This essentially means that we change the shape of the probability distributions. We might, for example, assume that the expected prices of electricity and natural gas would be higher, and re-solve the decision tree to determine whether such a change affected the optimal decision today. (We generally don't need to be concerned with changes in future decisions, as we can always revisit them later.) If the optimal decision does not change, we need not worry. If it does, we may be able to gather additional information to improve the characterization of the uncertainties, or invest in specific hedge instruments that reduce those uncertainties, and re-run the analysis.

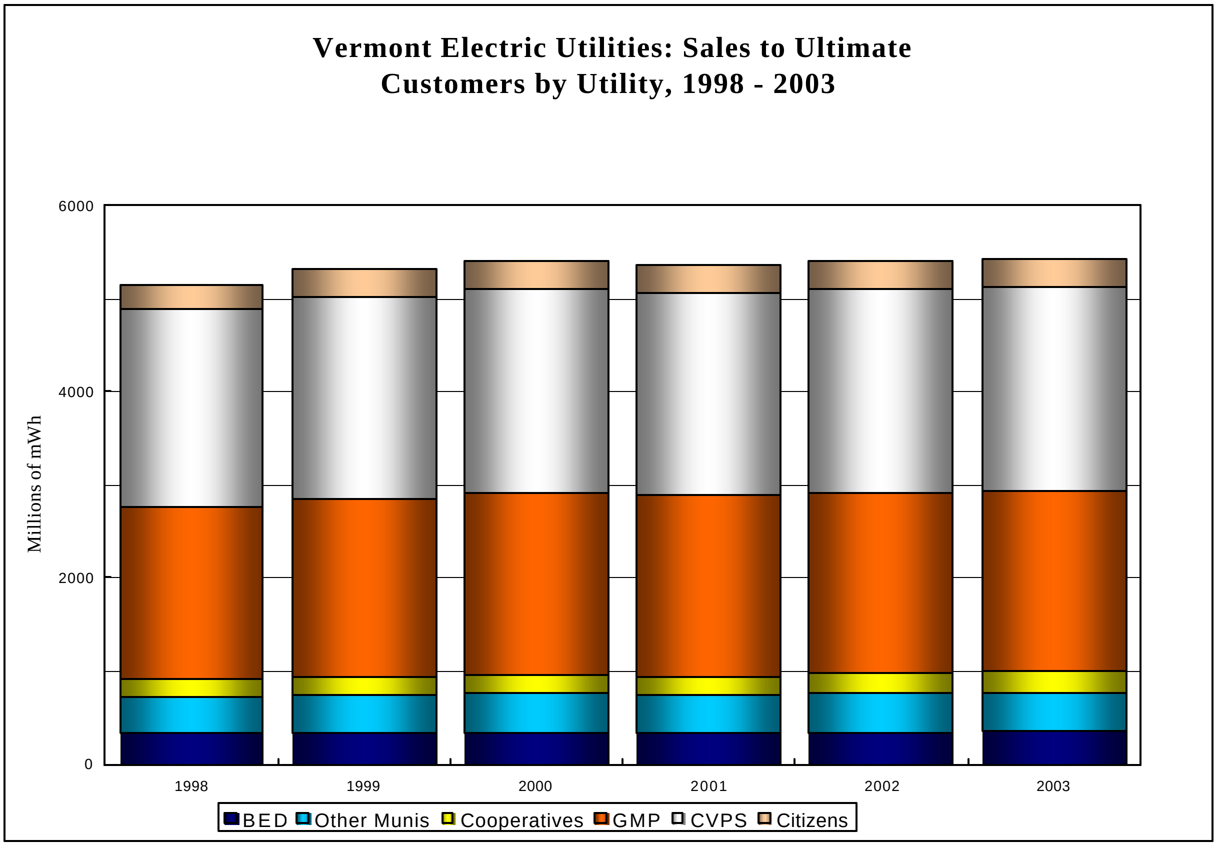
OTHER EMPIRICAL TECHNIQUES

The decision tree approach is just one form of decision analysis. Another common technique, which can be very useful when there are a number of uncertainties to consider whose interactions are not clear, is Monte-Carlo modeling. Monte-Carlo models can be particularly useful in valuing specific hedge instruments, such as generating resource options contracts, especially when the underlying assumptions do not conform to "traditional" financial options model assumptions.[4]

[4] The best known financial option model is probably the Black-Scholes option pricing model. Although this model is used for valuing stock options, its use for electric generating options contracts, especially long-term contracts, is problematic, and can lead to significant over-valuation of such contracts.

Appendix C : Vermont Utilities; Sales, Revenues and Typical Bills

Table C-1



Sales to Ultimate Customers by Utility (kWh)

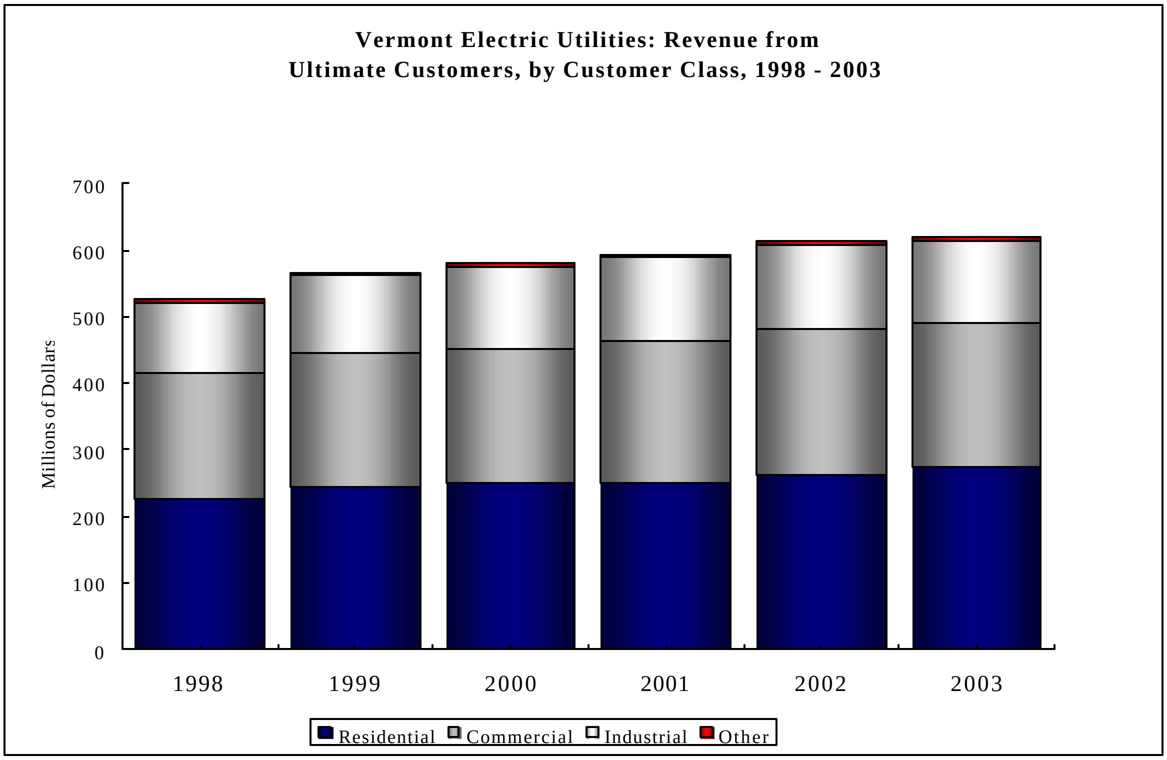
Utility	1998	1999	2000	2001	2002	2003
Small Privates	201,848,016	215,575,796	218,803,671	215,635,029	223,464,972	214,489,354
Citizens	276,416,000	291,172,000	303,351,000	305,446,000	302,182,000	305,767,000
CVPS	2,125,930,000	2,172,798,000	2,199,561,000	2,161,059,000	2,186,344,000	2,198,162,000
GMP	1,840,948,000	1,901,783,000	1,951,065,000	1,956,147,000	1,943,455,000	1,933,728,000
Cooperatives	189,302,000	196,273,000	201,501,000	201,390,000	206,956,000	218,268,000
Other Munis	396,196,051	408,608,930	415,295,628	410,578,716	420,961,640	422,755,111
BED	327,166,000	337,009,000	338,628,000	332,802,000	340,502,000	349,920,000
Total	5,357,806,067	5,523,219,726	5,628,205,299	5,583,057,745	5,623,865,612	5,643,089,465

Percentage of Sales to Ultimate Customers by Utility

Utility	1998	1999	2000	2001	2002	2003
Small Privates	3.77	3.90	3.89	3.86	3.97	3.80
Citizens	5.16	5.27	5.39	5.47	5.37	5.42
CVPS	39.68	39.34	39.08	38.71	38.88	38.95
GMP	34.36	34.43	34.67	35.04	34.56	34.27
Cooperatives	3.53	3.55	3.58	3.61	3.68	3.87
Other Munis	7.39	7.40	7.38	7.35	7.49	7.49
BED	6.11	6.10	6.02	5.96	6.05	6.20
Total	100.00	100.00	100.00	100.00	100.00	100.00

Source: Annual Reports

Table C-2



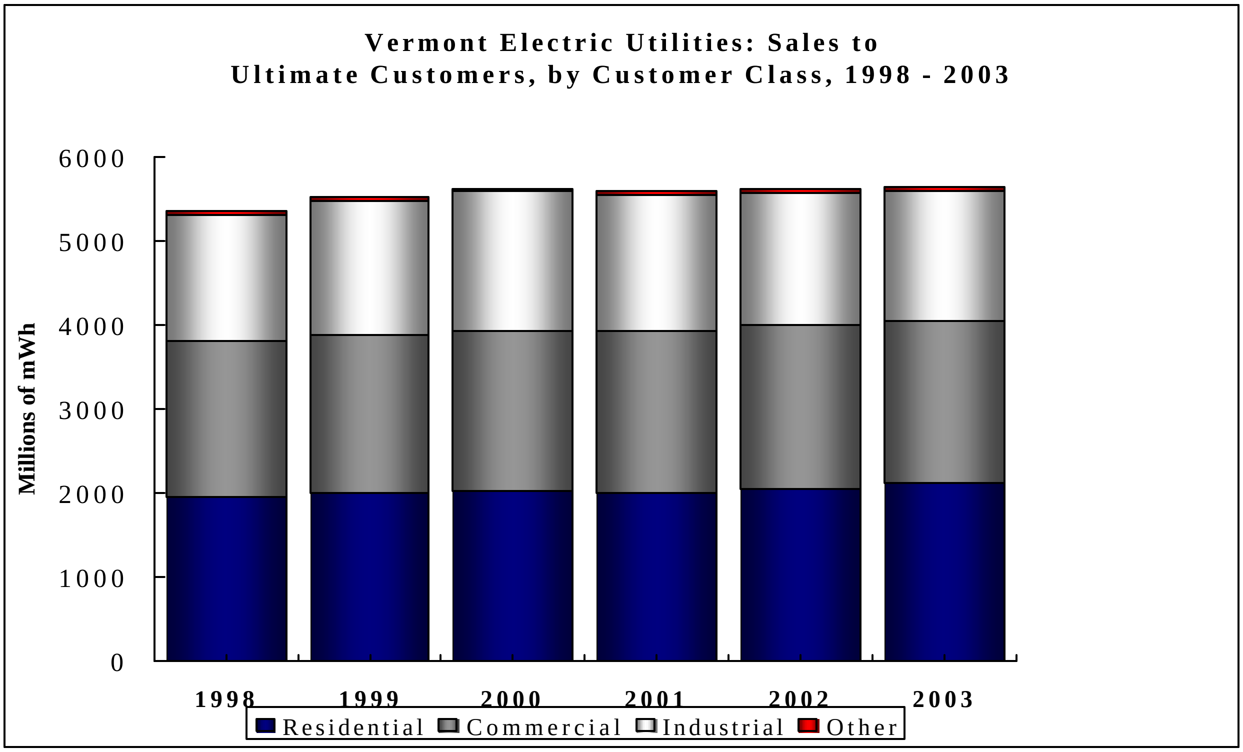
Revenue from Ultimate Customers by Customer Class

	1998	1999	2000	2001	2002	2003
Residential	227,100,330	242,727,167	250,524,813	251,362,859	263,232,473	273,888,505
Commercial	187,879,236	202,492,316	202,040,252	210,964,392	217,804,382	215,241,584
Industrial	105,939,037	115,806,097	120,894,392	125,619,073	125,235,961	125,074,556
Other	5,499,582	5,526,468	5,861,934	6,056,224	6,312,333	6,482,723
Total	526,418,185	566,552,048	579,321,391	594,002,548	612,585,149	620,687,368

Percentage of Revenue From Ultimate Customers

	1998	1999	2000	2001	2002	2003
Residential	43.14%	42.84%	43.24%	42.32%	42.97%	44.13%
Commercial	35.69%	35.74%	34.88%	35.52%	35.55%	34.68%
Industrial	20.12%	20.44%	20.87%	21.15%	20.44%	20.15%
Other	1.04%	0.98%	1.01%	1.02%	1.03%	1.04%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Table C-3



Sales to Ultimate Customers by Customer Class (kWh)

	1998	1999	2000	2001	2002	2003
Residential	1,951,303,712	1,993,990,616	2,034,714,985	2,009,278,870	2,046,101,168	2,128,701,848
Commercial	1,853,216,919	1,897,409,767	1,900,823,062	1,920,846,814	1,943,752,256	1,911,511,710
Industrial	1,514,355,515	1,593,169,050	1,652,162,500	1,611,750,379	1,592,436,197	1,561,371,381
Other	38,929,921	38,650,293	40,504,752	41,181,682	41,575,991	41,504,526
Total	5,357,806,067	5,523,219,726	5,628,205,299	5,583,057,745	5,623,865,612	5,643,089,465

Percentage of Sales to Ultimate Customers

	1998	1999	2000	2001	2002	2003
Residential	36.42%	36.10%	36.15%	35.99%	36.38%	37.72%
Commercial	34.59%	34.35%	33.77%	34.40%	34.56%	33.87%
Industrial	28.26%	28.84%	29.36%	28.87%	28.32%	27.67%
Other	0.73%	0.70%	0.72%	0.74%	0.74%	0.74%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

12/02/2004

TABLE D.4 TYPICAL RESIDENTIAL BILLS AS OF NOVEMBER 2004

UTILITY:			KWH 25	KWH 100	KWH 250	KWH 500	KWH 750	KWH 1000	KWH 2000	KWH 3000
BARTON										
Customer Charge		$7.43	$89.16	$89.16	$89.16	$89.16	$89.16	$89.16	$89.16	$89.16
NYPA Block	100	0.06626	$19.88	$79.51	$79.51	$79.51	$79.51	$79.51	$79.51	$79.51
Levelized rate	12	0.13944	$0.00	$0.00	$250.99	$669.31	$1,087.63	$1,505.95	$3,179.23	$4,852.51
Surcharge		0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EEU Charge		0.00318	$0.95	$3.82	$9.54	$19.08	$28.62	$38.16	$76.32	$114.48
Average Monthly Bill			$9.17	$14.37	$35.77	$71.42	$107.08	$142.73	$285.35	$427.97
BURLINGTON										
Customer Charge		$7.86	$94.32	$94.32	$94.32	$94.32	$94.32	$94.32	$94.32	$94.32
NYPA Block	200	0.05945	$17.84	$71.34	$142.68	$142.68	$142.68	$142.68	$142.68	$142.68
Peak Months	4	0.105309		$0.00	$21.06	$126.37	$231.68	$336.99	$758.22	$1,179.46
Off Peak Months	8	0.101427		$0.00	$40.57	$243.42	$446.28	$649.13	$1,460.55	$2,271.96
Surcharge		0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EEU Charge		0.002468	$0.74	$2.96	$7.40	$14.81	$22.21	$29.62	$59.23	$88.85
Average Monthly Bill			$9.41	$14.05	$25.50	$51.80	$78.10	$104.39	$209.58	$314.77
CITIZENS [1]*										
Customer Charge		$7.66	$91.92	$91.92	$91.92	$91.92	$91.92	$91.92	$91.92	$91.92
First Block(off-Peak)	250	0.11075	$16.61	$66.45	$166.13	$166.13	$166.13	$166.13	$166.13	$166.13
First Block (peak)	250	0.11086	$16.63	$66.52	$166.29	$166.29	$166.29	$166.29	$166.29	$166.29
Peak Months	6	0.12792		$0.00	$0.00	$191.88	$383.76	$575.64	$1,343.16	$2,110.68
Off Peak Months	6	0.11097		$0.00	$0.00	$166.46	$332.91	$499.37	$1,165.19	$1,831.01
Surcharge		0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EEU Charge		0.00318	$0.95	$3.82	$9.54	$19.08	$28.62	$38.16	$76.32	$114.48
Average Monthly Bill			$10.51	$19.06	$36.16	$66.81	$97.47	$128.13	$250.75	$373.38
CVPS										
Customer Charge		$11.38	$136.56	$136.56	$136.56	$136.56	$136.56	$136.56	$136.56	$136.56
Levelized rate	12	0.1174	$35.22	$140.88	$352.20	$704.40	$1,056.60	$1,408.80	$2,817.60	$4,226.40
Surcharge		0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EEU Charge		0.00318	$0.11	$0.45	$1.12	$2.24	$3.36	$4.48	$8.96	$13.44
Average Monthly Bill			$14.32	$23.16	$40.82	$70.27	$99.71	$129.15	$246.93	$364.70
ENOSBURG										
Customer Charge		$7.66	$91.92	$91.92	$91.92	$91.92	$91.92	$91.92	$91.92	$91.92
NYPA Block	125	0.05593	$16.78	$67.12	$83.90	$83.90	$83.90	$83.90	$83.90	$83.90
Levelized rate	12	0.1352	$0.00	$0.00	$202.80	$608.40	$1,014.00	$1,419.60	$3,042.00	$4,664.40
Surcharge		0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EEU Charge		0.00318	$0.95	$3.82	$9.54	$19.08	$28.62	$38.16	$76.32	$114.48
Average Monthly Bill			$9.14	$13.57	$32.35	$66.94	$101.54	$136.13	$274.51	$412.89
GMP										
Customer Charge		$11.27	$135.24	$135.24	$135.24	$135.24	$135.24	$135.24	$135.24	$135.24
Levelized rate	12	0.11146	$33.44	$133.75	$334.38	$668.76	$1,003.14	$1,337.52	$2,675.04	$4,012.56
Surcharge		0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EEU Charge		0.00318	$0.95	$3.82	$9.54	$19.08	$28.62	$38.16	$76.32	$114.48
Average Monthly Bill			$14.14	$22.73	$39.93	$68.59	$97.25	$125.91	$240.55	$355.19
HARDWICK										
Customer Charge		$9.18	$110.16	$110.16	$110.16	$110.16	$110.16	$110.16	$110.16	$110.16
NYPA Block	100	0.04881	$14.64	$58.57	$58.57	$58.57	$58.57	$58.57	$58.57	$58.57
Levelized rate	12	0.13886	$0.00	$0.00	$249.95	$666.53	$1,083.11	$1,499.69	$3,166.01	$4,832.33
Surcharge		0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EEU Charge		0.00318	$0.95	$3.82	$9.54	$19.08	$28.62	$38.16	$76.32	$114.48
Average Monthly Bill			$10.48	$14.38	$35.69	$71.20	$106.71	$142.22	$284.26	$426.30

[1] Acquired by VEC 4/1/04

			KWH 25	KWH 100	KWH 250	KWH 500	KWH 750	KWH 1000	KWH 2000	KWH 3000
HYDE PARK										
Customer Charge		$9.11	$109.32	$109.32	$109.32	$109.32	$109.32	$109.32	$109.32	$109.32
NYPA Block	100	0.0589	$17.67	$70.68	$70.68	$70.68	$70.68	$70.68	$70.68	$70.68
Levelized rate	12	0.10566		$0.00	$190.19	$507.17	$824.15	$1,141.13	$2,409.05	$3,676.97
Surcharge		0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EEU Charge		0.00318	$0.95	$3.82	$9.54	$19.08	$28.62	$38.16	$76.32	$114.48
Average Monthly Bill			$10.66	$15.32	$31.64	$58.85	$86.06	$113.27	$222.11	$330.95
JACKSONVILLE										
Customer Charge		$5.15	$61.80	$61.80	$61.80	$61.80	$61.80	$61.80	$61.80	$61.80
NYPA Block	175	0.0499	$14.97	$59.88	$104.79	$104.79	$104.79	$104.79	$104.79	$104.79
Peak Months	5	0.1347		$0.00	$50.51	$218.89	$387.26	$555.64	$1,229.14	$1,902.64
Off Peak Months	7	0.1064		$0.00	$55.86	$242.06	$428.26	$614.46	$1,359.26	$2,104.06
Surcharge	3/04	0.2497	$19.17	$30.38	$68.16	$156.70	$245.23	$333.77	$687.92	$1,042.07
EEU Charge		0.00318	$0.95	$3.82	$9.54	$19.08	$28.62	$38.16	$76.32	$114.48
Average Monthly Bill			$8.07	$12.99	$29.22	$66.94	$104.66	$142.38	$293.27	$444.15
JOHNSON Bills rendered 3/1/04										
Customer Charge		$6.08	$72.96	$72.96	$72.96	$72.96	$72.96	$72.96	$72.96	$72.96
NYPA Block	100	0.05267	$15.80	$63.20	$63.20	$63.20	$63.20	$63.20	$63.20	$63.20
Levelized rate	12	0.08133		$0.00	$146.39	$390.38	$634.37	$878.36	$1,854.32	$2,830.28
Surcharge		0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EEU Charge		0.00318	$0.95	$3.82	$9.54	$19.08	$28.62	$38.16	$76.32	$114.48
Average Monthly Bill			$7.48	$11.67	$24.34	$45.47	$66.60	$87.72	$172.23	$256.74
LUDLOW										
Customer Charge		$5.63	$67.56	$67.56	$67.56	$67.56	$67.56	$67.56	$67.56	$67.56
NYPA Block	125	0.03438	$10.31	$41.26	$51.57	$51.57	$51.57	$51.57	$51.57	$51.57
Levelized rate	12	0.07751		$0.00	$116.27	$348.80	$581.33	$813.86	$1,743.98	$2,674.10
Surcharge		0.1088	$8.47	$11.84	$25.61	$50.91	$76.21	$101.51	$202.71	$303.90
EEU Charge		0.00318	$0.95	$3.82	$9.54	$19.08	$28.62	$38.16	$76.32	$114.48
Average Monthly Bill			$7.28	$10.37	$22.55	$44.83	$67.11	$89.39	$178.51	$267.63
LYNDONVILLE										
Customer Charge		$6.96	$83.52	$83.52	$83.52	$83.52	$83.52	$83.52	$83.52	$83.52
NYPA Block	100	0.05186	$15.56	$62.23	$62.23	$62.23	$62.23	$62.23	$62.23	$62.23
Levelized rate	12	0.10645		$0.00	$191.61	$510.96	$830.31	$1,149.66	$2,427.06	$3,704.46
Surcharge		0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EEU Charge		0.00318	$0.95	$3.82	$9.54	$19.08	$28.62	$38.16	$76.32	$114.48
Average Monthly Bill			$8.34	$12.46	$28.91	$56.32	$83.72	$111.13	$220.76	$330.39
MORRISVILLE										
Customer Charge		$5.47	$65.64	$65.64	$65.64	$65.64	$65.64	$65.64	$65.64	$65.64
NYPA Block	150	0.04897	$14.69	$58.76	$88.15	$88.15	$88.15	$88.15	$88.15	$88.15
Peak Months	5	0.14618		$0.00	$73.09	$255.82	$438.54	$621.27	$1,352.17	$2,083.07
Off Peak Months	7	0.11545		$0.00	$80.82	$282.85	$484.89	$686.93	$1,495.08	$2,303.23
Surcharge	2	0.1133	$9.10	$14.09	$34.86	$78.45	$122.05	$165.64	$340.02	$514.39
EEU Charge		0.00318	$0.95	$3.82	$9.54	$19.08	$28.62	$38.16	$76.32	$114.48
Average Monthly Bill			$7.53	$11.86	$29.34	$65.83	$102.32	$138.82	$284.78	$430.75
NORTHFIELD										
Customer Charge		$6.57	$78.84	$78.84	$78.84	$78.84	$78.84	$78.84	$78.84	$78.84
NYPA Block	100	0.05211	$15.63	$62.53	$62.53	$62.53	$62.53	$62.53	$62.53	$62.53
Levelized rate	12	0.11245		$0.00	$202.41	$539.76	$877.11	$1,214.46	$2,563.86	$3,913.26
Surcharge		0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EEU Charge		0.00318	$0.95	$3.82	$9.54	$19.08	$28.62	$38.16	$76.32	$114.48
Average Monthly Bill			$7.95	$12.10	$29.44	$58.35	$87.26	$116.17	$231.80	$347.43

			KWH 25	KWH 100	KWH 250	KWH 500	KWH 750	KWH 1000	KWH 2000	KWH 3000
ORLEANS										
Customer Charge		$7.19	$86.28	$86.28	$86.28	$86.28	$86.28	$86.28	$86.28	$86.28
NYPA Block	100	0.05487	$16.46	$65.84	$65.84	$65.84	$65.84	$65.84	$65.84	$65.84
Levelized rate	12	0.08674		$0.00	$156.13	$416.35	$676.57	$936.79	$1,977.67	$3,018.55
Surcharge	9/04	0.0566	$5.82	$8.61	$17.45	$32.18	$46.90	$61.63	$120.55	$179.46
EEU Charge		0.00318	$0.95	$3.82	$9.54	$19.08	$28.62	$38.16	$76.32	$114.48
Average Monthly Bill			$9.13	$13.71	$27.94	$51.64	$75.35	$99.06	$193.89	$288.72
READSBORO										
Customer Charge		$4.68	$56.16	$56.16	$56.16	$56.16	$56.16	$56.16	$56.16	$56.16
NYPA Block	100	0.04029	$12.09	$48.35	$48.35	$48.35	$48.35	$48.35	$48.35	$48.35
Levelized rate	12	0.08952		$0.00	$161.14	$429.70	$698.26	$966.82	$2,041.06	$3,115.30
Surcharge		0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EEU Charge		0.00318	$0.95	$3.82	$9.54	$19.08	$28.62	$38.16	$76.32	$114.48
Average Monthly Bill			$5.77	$9.03	$22.93	$46.11	$69.28	$92.46	$185.16	$277.86
ROCHESTER										
Customer Charge		$10.74	$128.88	$128.88	$128.88	$128.88	$128.88	$128.88	$128.88	$128.88
Peak Months	6	0.1602	$24.03	$96.12	$240.30	$480.60	$720.90	$961.20	$1,922.40	$2,883.60
Off Peak Months	6	0.0882	$13.23	$52.92	$132.30	$264.60	$396.90	$529.20	$1,058.40	$1,587.60
Surcharge		0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EEU Charge		0.00318	$0.95	$3.82	$9.54	$19.08	$28.62	$38.16	$76.32	$114.48
Average Monthly Bill			$13.92	$23.48	$42.59	$74.43	$106.28	$138.12	$265.50	$392.88
STOWE										
Customer Charge		$8.07	$96.84	$96.84	$96.84	$96.84	$96.84	$96.84	$96.84	$96.84
NYPA Block	150	0.05396	$16.19	$64.75	$97.13	$97.13	$97.13	$97.13	$97.13	$97.13
Peak Months	5	0.16149		$0.00	$80.75	$282.61	$484.47	$686.33	$1,493.78	$2,301.23
Off Peak Months	7	0.09153		$0.00	$64.07	$224.25	$384.43	$544.60	$1,185.31	$1,826.02
Surcharge		0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EEU Charge		0.00318	$0.95	$3.82	$9.54	$19.08	$28.62	$38.16	$76.32	$114.48
Average Monthly Bill			$9.50	$13.78	$29.03	$59.99	$90.96	$121.92	$245.78	$369.64
SWANTON										
Customer Charge		$6.93	$83.16	$83.16	$83.16	$83.16	$83.16	$83.16	$83.16	$83.16
NYPA Block	100	0.03858	$11.57	$46.30	$46.30	$46.30	$46.30	$46.30	$46.30	$46.30
Levelized rate	12	0.0957		$0.00	$172.26	$459.36	$746.46	$1,033.56	$2,181.96	$3,330.36
Surcharge		0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EEU Charge		0.00318	$0.95	$3.82	$9.54	$19.08	$28.62	$38.16	$76.32	$114.48
Average Monthly Bill			$7.97	$11.11	$25.94	$50.66	$75.38	$100.10	$198.98	$297.86
VEC										
Customer Charge		$9.69	$116.28	$116.28	$116.28	$116.28	$116.28	$116.28	$116.28	$116.28
NYPA Block	100	0.0699	$20.97	$83.88	$83.88	$83.88	$83.88	$83.88	$83.88	$83.88
Levelized rate	12	0.1336		$0.00	$240.48	$641.28	$1,042.08	$1,442.88	$3,046.08	$4,649.28
Surcharge		0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EEU Charge		0.00318	$0.95	$3.82	$9.54	$19.08	$28.62	$38.16	$76.32	$114.48
Average Monthly Bill			$11.52	$17.00	$37.52	$71.71	$105.91	$140.10	$276.88	$413.66
VT. MARBLE										
Customer Charge		$3.66	$43.92	$43.92	$43.92	$43.92	$43.92	$43.92	$43.92	$43.92
First Block	100	0.0765	$22.95	$91.80	$91.80	$91.80	$91.80	$91.80	$91.80	$91.80
Peak Months	4	0.0899		$0.00	$53.94	$143.84	$233.74	$323.64	$683.24	$1,042.84
Off Peak Months	8	0.0698		$0.00	$83.76	$223.36	$362.96	$502.56	$1,060.96	$1,619.36
Surcharge		0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EEU Charge		0.00318	$0.95	$3.82	$9.54	$19.08	$28.62	$38.16	$76.32	$114.48
Average Monthly Bill			$5.65	$11.63	$23.58	$43.50	$63.42	$83.34	$163.02	$242.70

			KWH 25	KWH 100	KWH 250	KWH 500	KWH 750	KWH 1000	KWH 2000	KWH 3000
WEC										
Customer Charge		$9.24	$110.88	$110.88	$110.88	$110.88	$110.88	$110.88	$110.88	$110.88
NYPA Block	150	0.07387	$22.16	$88.64	$132.97	$132.97	$132.97	$132.97	$132.97	$132.97
Levelized rate	12	0.16207		$0.00	$194.48	$680.69	$1,166.90	$1,653.11	$3,597.95	$5,542.79
Surcharge		0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EEU Charge		0.002254	$0.68	$2.70	$6.76	$13.52	$20.29	$27.05	$54.10	$81.14
Average Monthly Bill			$11.14	$16.85	$37.09	$78.17	$119.25	$160.33	$324.66	$488.98

Appendix D: Abbreviations

A - J	Averch - Johnson
AARP	American Association Of Retired Persons
AC	Alternating Current
ACE	Account Correction For Efficiency
ACRS	Advisory Committee On Reactor Safeguards
AGC	Automatic Generation Control
AIPM	Area Investment Planning Model
ANR	Vermont Agency Of Natural Resources
ARR	Auction Revenue Rights
ASAI	Average Service Availability Index
ASC	Area Specific Collaboratives
Bbl	Barrel
BED	Burlington Electric Department
BWR	Boiling Water Reactor
C&I	Commercial And Industrial
CAFE	Corporate Average Fuel Efficiency Standards
CAID	Customer Average Interruption Duration
CEE	Consortium For Energy Efficiency
CEE	Consortium For Energy Efficieny
CFC	Chlorinated Flurocarbons
CH_4	Methane
CHP	Combined Heat And Power
Citizens	Citizens Communications Company
CO	Carbon Monoxide
CO2	Carbon Dioxide
COS	Cost Of Service
CPG	Certificate Of Public Good
CPI	Consumer Price Index
CSC	Cross Sound Cable
CSEDS	Combined State Energy Data System
CTR	Capacity Transfer Rights
CUC	Citizens Utilities Corporation
CVPS	Central Vermont Public Service
DA	Day Ahead

DA	Decision Analysis
DC	Direct Current
DCA	Designated Constrained Area
DG	Distributed Generation
DOE	U.S. Department Of Energy
DOE/EIA	U.S. Department of Energy/Energy Information Administration
DPS	Departement Of Public Service
DR	Demand Response
DSM	Demand Side Management
DSP	Disposable State Personal Income
DU	Distributed Utility
DUP	Distributed Utility Planning
EEC	Energy Efficiency Charge
EED	Energy Efficiency Division
EEU	Energy Efficiency Utility
EIA	Energy Information Administration/
EMF	Electro Magnetic Fields
EMS	Energy Management Systems
EPA	U.S. Environmental Protection Agency
EPAct	Energy Policy Act
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council Of Texas
EVT	Efficency Vermont
EWGs	Exempt Wholesale Generators
FE	First Energy
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
FTR	Financial Transmission Rights
GDP	Gross Domestic Product
GHG	Greenhouse Gases
GMP	Green Mountain Power
GSP	Gross State Product
GWh	Giga Watt Hours
GWP	Global Warming Potential
HEAT	Home Energy Audit Team
HFCs	Fluorinated Hydrocarbons
HQ	Hydro Québec

HUD	Housing And Urban Development Adminstration
HVAC	Heating, Ventilating, And Air Conditioning
HVDC	High Voltage Direct Current
IARC	International Agency For Research On Cancer
ICA	Interregional Coordination And Seams Reduction Agreement
ICA	Interregional Coordination Agreement
ICAP	Installed Capacity
ICC	Illinois Commerce Commission
ICNIRP	Internation Commision On Non-Ionizing Radiation Protection
IPPs	Independent Power Producers
IRP	Integrated Resource Plan
ISO	Independent System Operator
ISO-NE	Independent System Operator Of New England
JCP&L	Jersey Central Power & Light
KCC	Kansas Corporation Commission
kV	Kilo-Volt
KW	Kilowatt
kWh	Kilo-Watt-Hour
LCIP	Least Cost Integrated Plans
LFG	Landfill Gas
LICAP	Location-Based Capacity Rules
LIHEAP	Low Income Heating Energy Assistance Program
LMP	Locational Marginal Pricing
LNG	Liquified Natural Gas
LOLE	Loss Of Load Expectation
LOLP	Loss Of Load Probability
LSE	Load Serving Entities
MDCC	Marginal Distribution Capacity Cost
MDPU	Massachusetts Department Of Public Utilities
MMTCE	Millions Of Metric Tons Of Carbon Equivalents
MOU	Memorandum Of Understanding
MSS	Multi-Settlement System
MTCDE	Metric Tons Of Carbon Dioxide Equivalent
MTCE	Metric Tons Of Carbon Equivalent
mW	Mega Watt
MWH	Mega Watt Hour
N2O	Nitrous Oxide
NAAQS	National Ambient Air Quality Standards

NEADA	National Energy Assistance Directors' Association
NECPUC	New England Conference of Public Utility Commissioners
NEEP	Northeast Energy Efficiency Partnerships
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Council
NEWSV	New England Waste Services Of Vermont
NIEHS	National Institute Of Environmental Health Sciences
NLP	Northern Loop Project
NO	Nitric Oxide
NO2	Nitrogen Dioxide
NOPR	Notice Of Proposed Rulemaking
NOX	Oxides Of Nitrogen
NPCC	Northeast Power Coordinating Council
NRA	Restated Nepool Agreement
NRC	Nuclear Regulatory Commission
NRP	Northwest Reliability Project
NYISO	New York Independent System Operator
NYPA	New York Power Authority
O_3	Ozone
OASIS	Real-Time Open Access Reporting And Information Systems
OATT	Open Access Transmission Tariff
OPEC	Organization Of Petroleum Exporting Countries
PAC	Planning Advisory Committee
PAR	Phase Angle Regulator
Pb	Lead
PBR	Performance Based Ratemaking
PCB	Poly-Chlorinated Biphenyls
PFCs	Poly-Fluorinated Compounds
PIPP	Percentage Of Income Payment Plan
PJM	Pennsylvania, New Jersey And Maryland
Plan	*The Electric Plan*
PM	Particle Matter
PPA	Power Purchase Agreement
ppm	Parts Per Million
PSB	Vermont Public Service Board
PSDAR	Post Shutdown Decommissioning Activities Report
PTF	Pool Transmission Facilities

PUC	Public Utility Commission
PUHCA	Public Utility Holding Company Act
PURPA	Public Utility Regulatory Policies Act Of 1978
PUSH	Peaking Unit Safe Harbor
PV	Photovoltaic
QF	Qualifying Facility
RAM	Reliability Assurance Market
RBES	Vermont’s Residential Energy Code
RCS	Residential Conservation Service
REEP	Residential Energy Efficiency Program
REMI	Regional Economic Models, Inc.
RERC	Renewable Energy Resource Center
RFP	Requests For Proposals
RMR	Reliability Must Run
RNA	Restated Nepool Agreement
RNC	Residential New Construction Program
RNS	Regional Network Service
ROE	Return On Equity
ROR	Rate Of Return
RPS	Renewables Portfolio Standard
RR	Renewable Resources
RSC	Regional State Committee
RSP	Regional System Plan
RT	Real Time
RTEP	Regional Transmission Expansion Planning
RTEP	Regional Transmission Expansion Plan
RTEP03	The Current Regional Transmission Expansion Plan
RTO	Regional Transmission Operator
SAID	System Average Interruption Duration
SAIF	System Average Interruption Frequency:
SBC	System Benefit Charge
SEDR	State Energy Data Report
SF6	Sulfur Hexafluoride
SMD	Standard Market Design
SO_2	Sulfur Dioxide
STC	Standard Test Conditions
T&D	transmission and distribution

TCA	transmission cost allocation rules
TEAC	Transmission Expansion Advisory Committee
TLR	Transmission Loading Relief
TO'S	Transmission Owners
TOA	Transmission Operating Agreement
TOU	Time-of-use
TRB	Total resource benefit
TSP	Total Suspended Particulate
UCAP	Unforced Capacity
USGen	U.S. Generating Company
µg /m3	micrograms per cubic meter
µg/dL	micrograms per deciliter
VaR	value-at-risk
VDH	Vermont Department Of Health
VEC	Vermont Electric Cooperative
VED	Vermont Electric Division
VEIC	Vermont Energy Investment Corporation
VELCO	Vermont Electric Power Company
VETCO	Vermont Electric Transmission Company
VGS	Vermont Gas Systems
VIECAP	Vermont Industrial Energy Conservation Advisory Program
VIWS	Vermont Integrated Waste Solutions
VJO	Vermont Joint Owners
VOC	Volatile Organic Compound
VPPSA	Vermont Public Power Supply Authority
VPX	Vermont Power Exchange
VRD	Virtual Regional Dispatch
VRPSAA	Vermont Renewable Power Supply Acquisition Authority
VY	Vermont Yankee
WACC	Weighted Average Cost Of Capital
WAP	Weatherization Assistance Program
WEC	Washington Electric Cooperative
WPPSS	Washington Public Power Supply System's
WWTF	Wastewater Treatment Facilities

Appendix E: Vermont Population Patterns of Growth T&D Constrained Areas

As part of the Phase II Memorandum of Understanding in Docket No. 6290, ten different Area Specific Collaboratives were formed. Figure E-3 shows the ASC. Figures E-1 and E-2 show population and population density change. Load growth associated with growth in population and population density change are important determinants of transmission constraints.

The ASC's include areas where local distribution and/or subtransmission, and possibly high voltage transmission systems are or soon will be unable to reliably serve area load.

The list of ASC's include the following areas:

- Central Area DUP Target Area
- Milton Distribution DUP Target Area
- Milton Subtransmission DUP Target Area
- Southern Loop DUP Target Area
- Stratton Distribution DUP Target Area
- Tafts Corner Substation DUP Target Area
- Digital Injection Line DUP Target Area
- Lamoille County Loop DUP Target Area
- Mount Snow DUP Target Area
- White River Junction DUP Target Area

Figure E-1 Vermont Population by Town

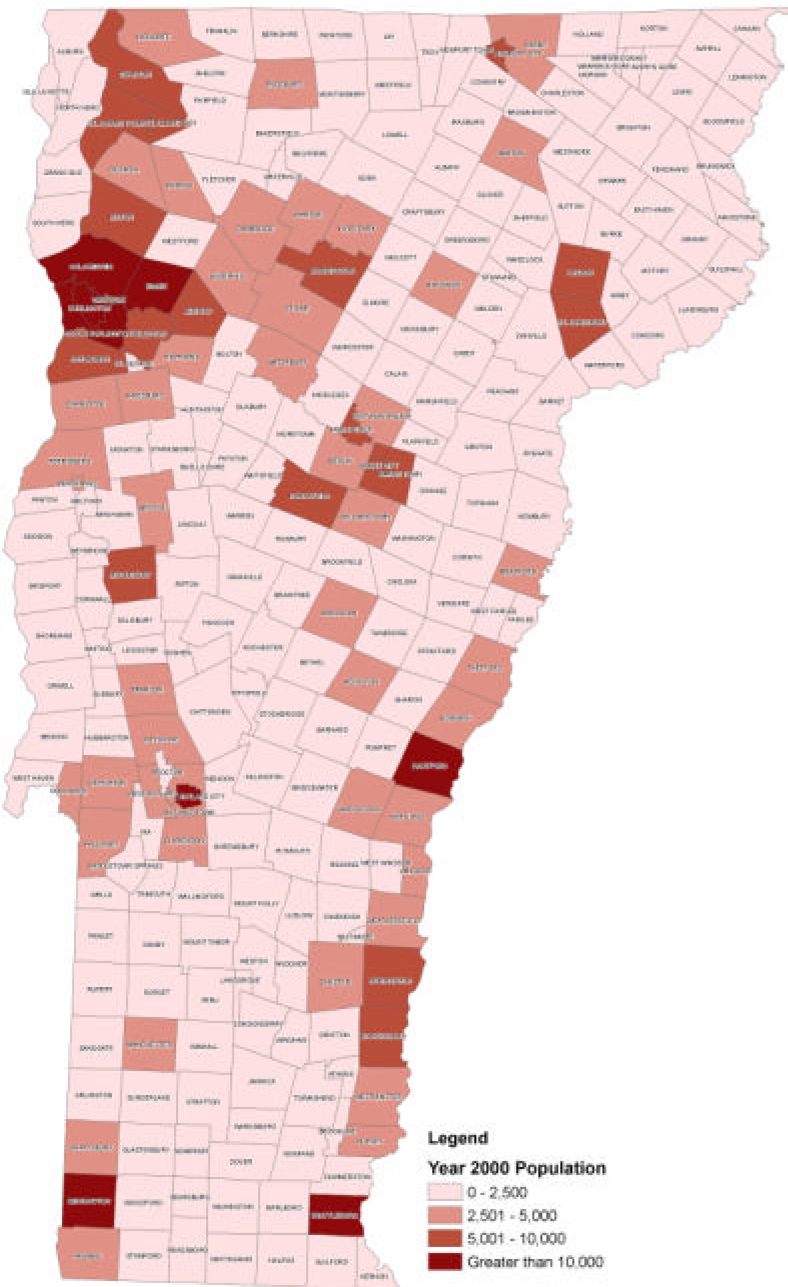


Figure E-2 Vermont Population Density Change 1990- 2000

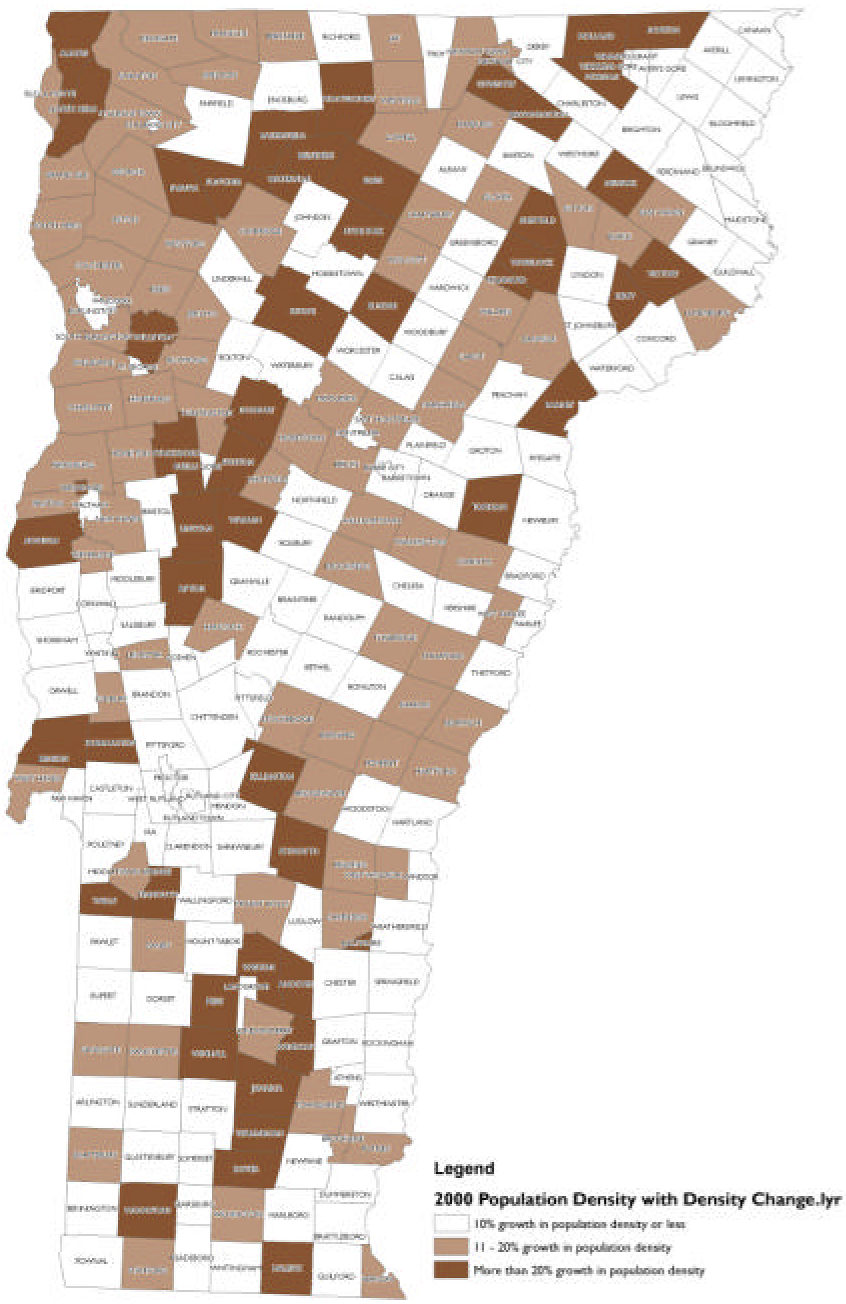


Figure E-3
T&D Constrained Areas as Reflected in
Current Area Specific Collaborative (ASCs defined in Docket 6290)

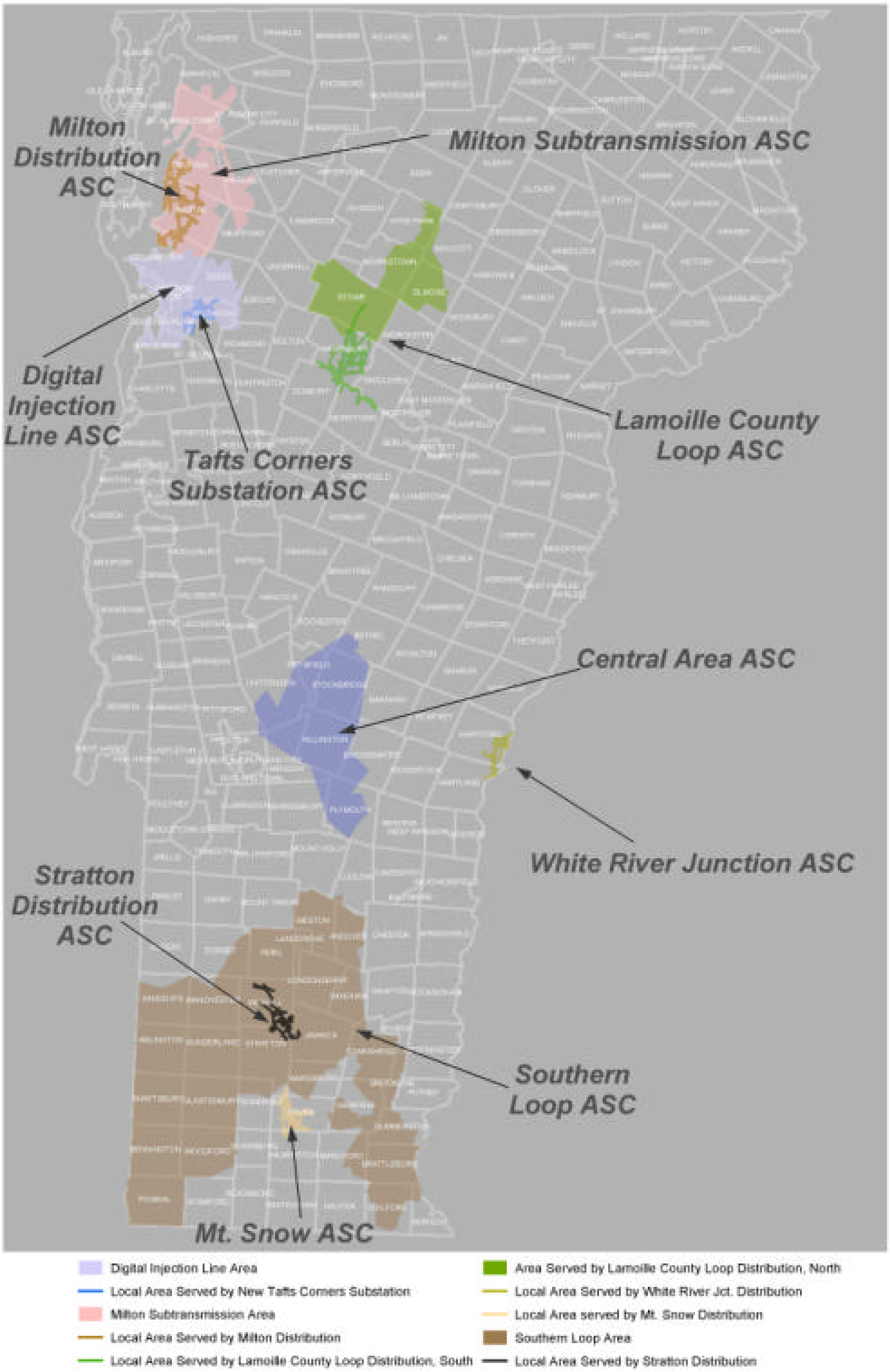
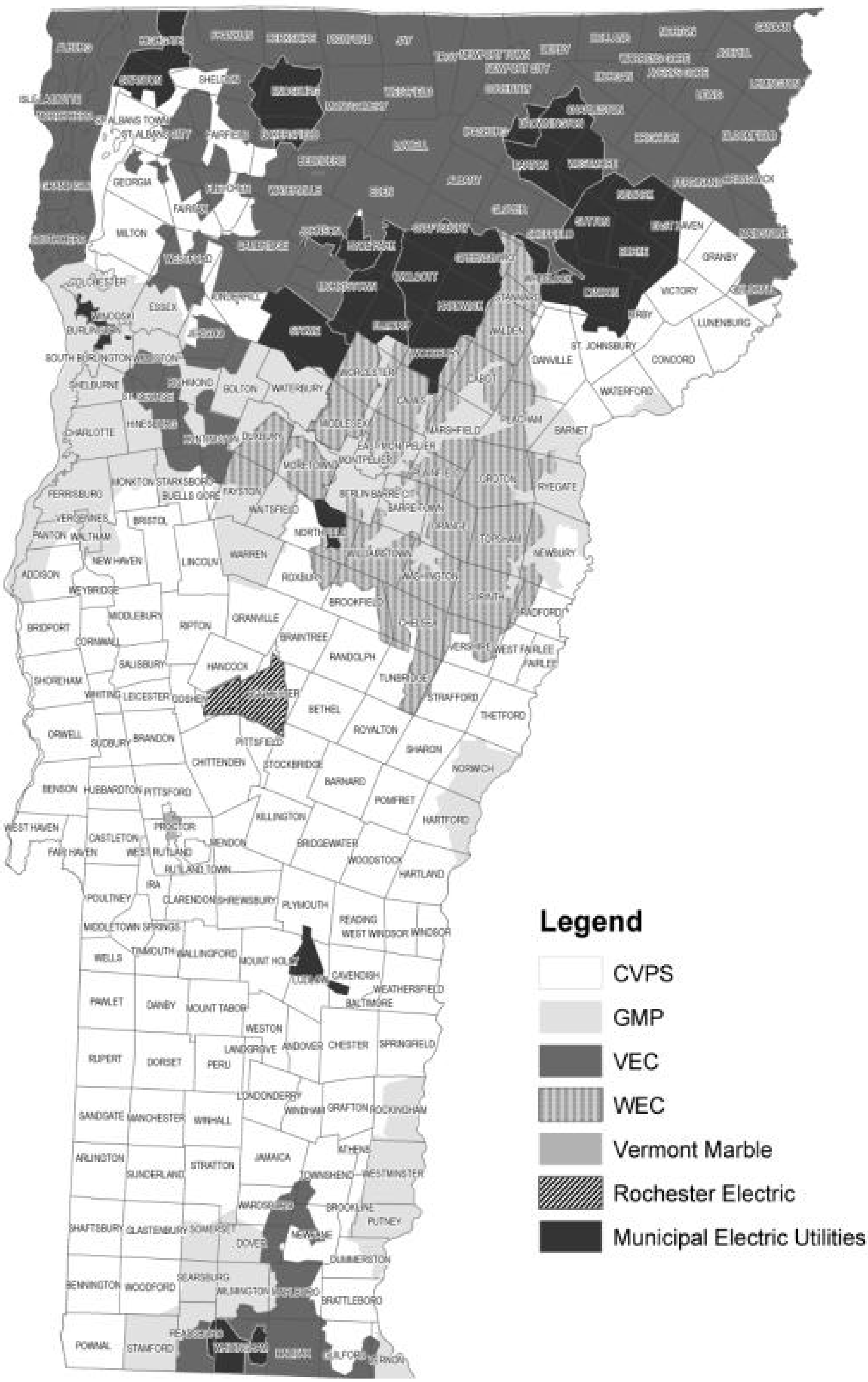


Figure E-4 Electric Utilities Franchise Areas



Appendix F: Guidelines for Distributed Utility Planning ("DUP")

In the planning process, the utility has an obligation to:

- Design its transmission and distribution ("T&D") system to meet expected normal loads.
- Design its T&D system to meet first-contingency loads, where justified and feasible, given the density and spatial distribution of load.
- Where T&D supply problems are experienced or projected,
  - * analyze alternatives at a level of detail commensurate with the scale of the problems and the costs of proposed solutions.
  - * re-configure the system to meet loads at the lowest feasible cost before any equipment upgrades are contemplated.
  - * seek the combination of DSM,[1] distributed generation ("DG"), and traditional T&D investments that solves the problem at the lowest net cost, considering all costs, benefits and risks.

These guidelines are intended to apply to the resolution of T&D supply problems and discuss the last point above: the process for including DSM and distributed generation in the T&D planning process to reduce the cost of maintaining the reliability, stability, safety, and quality of power delivery.

1. Identify areas with existing or projected T&D supply problems (*i.e.*, capacity-constrained areas).

   a) Identify areas (usually defined by substation or feeder number) in which major T&D investments are planned or projected to solve a T&D supply problem. Emerging problems should be identified as long in advance as practicable, to identify as many situations as possible in which intensified, targeted DSM and distributed generation may be helpful, while those strategies have sufficient lead time to be effective.

   b) Determine whether the problem identified in 1.a) above would be avoided or deferred, or the cost of resolving it would be reduced, by reductions in load. If not, DUP is not applicable.

1 In these Guidelines, demand-side management ("dsm") includes actions that reduce consumer requirements for electric T&D service, including efficiency, fuel choice and load control measures (which may include special contracts and other rate-design features).

c) Identify the Critical Element(s): the feeder, substation, and/or transmission line expected to be overloaded in the absence of T&D reinforcement.[2]

2. Define the region in which load reductions would be reasonably expected to contribute to deferring or avoiding the need for the T&D reinforcement, or otherwise reducing the cost of resolving the problem identified in 1.a) above.

a) This DUP region includes both areas served by the Critical Element and areas served by other T&D facilities to which load can be transferred from the Critical Element (subject to normal engineering guidelines).[3]

b) If the Critical Element is a feeder, the DUP region includes the area served by the feeder and its laterals or taps, and potentially

i) parallel feeders close to laterals or taps that run from the Critical Element.

ii) feeders that are connected to the Critical Element through a normally open switch.

c) If the Critical Element is a distribution substation, the potential DUP region includes

i) the area normally served by the feeders from that substation;

ii) the entire area normally served by other substations serving feeders that can take load off the feeders served by the Critical Element in either of the ways described above.

d) If the Critical Element is a transmission line (or substation), the potential DUP region includes

i) the area downstream from the Critical Element,[4] and

ii) the area served by any transmission line (or substation) that can pick up load from the Critical Element

a) directly by serving a distribution substation currently downstream of the Critical Element, or

b) indirectly by transfer of feeder loads from substations on the Critical Element to substations on the alternative line.

e) If the critical load is a first-contingency overload, include in the relevant area all of the circuits that contribute to a first-contingency overload on the Critical Element. In particular, consider:

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2 Due to reconfiguration and ability to share loads, as well as the possibility of overloads at multiple voltage levels, a particular problem area may have several Critical Elements.

3 The extent of reconfiguration of the distribution system may be limited by reliability, stability, operational, safety or cost considerations.

4 For transmission lines served at both ends, “downstream” is defined for the conditions creating the critical load.

i) All feeders connected to the end of Critical Element through a normally open switch,

ii) All feeders parallel to the Critical Element, and

iii) All feeders parallel to feeders connected to the end of the Critical Element through a normally open switch.

f) Include other utilities' facilities in assessing options for the incumbent utility to serve its customers' loads at societal least cost.[5]

i) Consider supply options that use the substations and feeders of other utilities, where available.

ii) Coordinate targeted DSM with adjacent utilities as an option for reducing loads on the Critical Element.

3. Identify deferrable costs and the load reductions that would be needed to defer those costs for various periods of time.[6]

a) Specify the magnitude, shape, and timing of the load reduction necessary to avoid T&D expenditures over the identified time periods.

i) Use the relevant load forecast on which project planning is based.[7]

ii) Determine which peaks and other high load hours are expected to affect the overloading problem.[8]

b) Include all reasonably foreseeable effects of load reductions on T&D timing. With continuous load growth, additional elements, especially at different voltage levels may become overloaded over time.

4. Compute the benefits of DSM load reductions:

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5 The purpose of DUP is to allow the utility to continue to serve its customers and its service territory at the minimum cost to society. Each utility is responsible for conducting dup to minimize the costs of resolving supply problems on its own system, as well as the costs of resolutions for which the utility will be charged. Each utility will have a duty to consult and cooperate reasonably with requests of other utilities to take measures to solve T&D problems on the other utilities' systems, with costs equitably allocated to the utility whose customers cause the need for, or receive the benefits of, measures to be taken. The utility seeking cooperation should petition the Board in the event that another utility is not fulfilling its duty to cooperate reasonably.

6 Load reductions may be able to avoid the T&D project permanently or delay it, depending upon the pattern of load growth and the regional DG and dsm potential. With continuous load growth, longer deferrals will require larger load reductions in each succeeding year.

7 Where load growth is highly uncertain, incorporating relevant annual load projections and sensitivity analysis around those projections may more meaningfully identify when actions are required than a single forecast.

8 Timing of peaks may vary between portions of the dup region.

a) In cases where the entire T&D expenditure is avoided, determine the total present value revenue requirements (PVRR) including O&M and net of any change in losses.[9]

b) In cases where the T&D expenditure is deferred, determine the value of delaying the project one year (the capital investment times the real-levelized carrying charge, plus O&M, net of any change in losses).

c) Using (b), compute the total present value of cost deferral as a function of the number of years of deferral.

d) To the DUP-region T&D value, add the value of avoided energy, avoided generation capacity (with any required reserve margin), and residual T&D (defined below).[10]

Include all benefits of load reductions, regardless of whether the reductions are coincident with the loads that drive the T&D expansion.

5. Seek targeted DSM retrofit, enhanced lost-opportunity programs, and distributed generation to relieve congestion.

a) Attempt to construct packages of DSM and DG with sufficient scale and acceptable costs.[11]

b) The potential for DSM retrofit programs depends on the installed mix of end uses, and on the lead time required to implement the programs.

c) The potential for market-driven programs depends on the rate at which the underlying events (e.g., new construction) occur. Estimates of this potential will generally be driven by the same factors to lead to the expectation of T&D constraints.[12]

d) Use the relevant load forecast on which T&D Plans are based to forecast DSM potential.[13] Where load growth is highly uncertain, incorporating relevant annual load projections and sensitivity analysis around those projections may more meaningfully identify when actions are required than a single forecast.

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9 The costs of the T&D expansion should be adjusted to reflect any associated benefits.

10 The benefits of load reduction should be adjusted to reflect the effects of T&D system re-configuration on losses or other costs.

11 As agreed upon in the Docket 5980 MOU, paragraph 35: "A DU shall be required to ensure that DSM implementation undertaken as part of DUP is conducted in a manner that does not create lost opportunities, including but not limited to lost opportunities in the market segments targeted by the Core Programs, and appropriately inventories future potential savings. The Parties agree that DUP does not require a DU to secure DSM savings beyond those that will enable it to fulfill the DU's DUP planning and implementation responsibilities."

12 Distribution utilities may rely on the Energy Efficiency Utility for the estimation of potential from enhancements of the market-driven and other core statewide programs.

13 Recognize that some uncertainties are associated with DSM potential estimates. It may be useful to forecast a DSM potential estimate for each load forecast discussed in footnote 7, above.

6. Compute appropriate residual non-DUP-region T&D benefits resulting from reductions in load growth.

7. Select from among the available options (new T&D investment, DSM, and/or DG, with various levels of reconfiguration and use of other utilities' facilities) based on minimizing net societal costs, reflecting any of the following that are significant:[14]

    a) The avoided costs described above.

    b) Customer and utility expenditures and savings.

    c) Changes in losses due to DSM, DG, and T&D alternatives.

    d) Any costs of integrating DG into to the distribution system.

    e) Any power-quality or reliability benefits of DG or T&D to host facilities.

    f) Important case specific differences in system safety, reliability and stability not addressed by interconnection standards or other generic provisions approved by the Vermont Public Service Board.

    g) Important differences in environmental and aesthetic effects.

    h) Important differences in risk and flexibility, including but not limited to significant risks of stranded T&D, DSM, or DG investment; or the emergence of new technologies.

If the selected option for solving the problem identified in 1.a) above is significantly inferior to one or more alternatives in a manner that cannot be fully monetized (system reliability, stability, environmental effects, aesthetics, risk, flexibility) , the utility should specify the cost or other benefits that outweigh the detriments.

8. Prepare an implementation plan for the selected option.

    a) Schedule resource additions to minimize cost, while maintaining flexibility and a high level of assurance that reliable service can be provided with the least-cost plan.

    b) Consider ownership, institutional and contractual arrangements (e.g., with the EU, other utilities, large customers, owners or operators) to manage financial and rate effects, to the extent possible, without significantly increasing societal costs or reducing reliability or probability of success.

    c) Determination that more than sufficient lead time exists for the preferred option may allow deferral of implementation until uncertainties are resolved and need is more imminent.

14 As agreed upon in the Docket 5980 Memorandum of Understanding (paragraph 34): "When considering the cost-effectiveness of alternatives to a new T&D investment, a DU shall choose the optimal investment strategy, determined under the societal test as defined in Docket No. 5270, subject to the constraints that the chosen strategy produces positive electric system net benefits including T&D cost savings, energy and capacity, and that it will enable the DU to operate its electric system in a safe and reliable manner."

d) Consider the hedge potential, and costs to acquire that potential, of each of the following:

i) Identified load-reduction potential from DSM in excess of expected needs;

ii) Identified load-serving potential from a DG resource in excess of expected needs; and

iii) Identified load-serving potential from a T&D facility in excess of expected needs.